CLASS VI PERMIT
AREA OF REVIEW AND CORRECTIVE ACTION PLAN

40 CFR 146.84(b)

LAPIS ENERGY (AR DEVELOPMENT) LP
PROJECT BLUE
EL DORADO, ARKANSAS

Prepared By:
GEOSTOCK SANDIA, LLC

Revision No. 0
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1.0 FACILITY INFORMATION

Facility/Project Name:	El Dorado Chemical Company / Lapis Energy Project Blue Class VI Injection Well No. 1
Facility/Project Contact:	Stijn Konings, Chief Geoscientist Lapis Energy LP 2950 N. Harwood St. Dallas, Texas 75201 (972) 757-6529 / skonings@lapisenergy.com
Well Locations:	Union County El Dorado, Arkansas Project Blue Class VI Injection Well No. 1 Latitude Coordinate: 33.26217733 Longitude Coordinate: -92.69162567

2.0 COMPUTATIONAL MODEL APPROACH

The modeling in this initial report is intended to present a conservative estimate of pressure build-up and plume extent over the injection and post injection life of the project. The data used in the model is derived from regional data and from wells proximal to the project site. Until information is obtained from the site specific well, this data is used as a basis for predicting the critical pressure and plume extent. This model represents a preliminary scenario for computational modeling for the Project Blue site, located at the El Dorado Chemical Company (EDCC) facility in Union County, Arkansas. A final simulation scenario following, acquisition of site-specific data from the Project Blue Injection Well will be completed and submitted prior to authorization to inject.

There are various physical and chemical processes that determine the efficiency and viability of CO_2 sequestration. **Table 1** contains some of considerations used in this model iteration. This study primarily considers the effects of stratigraphic trapping by the primary confining unit, to some degree capillary pressure trapping, and CO_2 solubility trapping. Relative permeability and capillary pressure curves used in the model are conservative. In addition, hysteresis (imbibition) trapping has not been modeled.

Table 1: Modeled considerations

Process	Modeled
Stratigraphic trapping (Primary Confining Unit)	Yes
Structural Trapping	N/A
Hydrodynamic Trapping	No
Residual Gas Trapping*	Yes
Capillary Trapping	Yes
CO_2 solubility trapping with the in-situ formation water	Yes
Mineralogical transformation	No

**Does not consider Hysteresis*

The static model was first built using geological parameters within Petrel for the two targeted injection zones (Lower Hosston and Cotton Valley Formations). It was then input into Eclipse 100 for dynamic simulation of the sequestration site to project the pressure and plume movement in the targeted injection zones. **Appendix 1** [redacted]

The Project Blue site has been simulated using two injection zones (with subzones), with each subzone modeled for 5-year periods independently, and not concurrently. The order of injection operations is as follows (in ascending order):

1) Cotton Valley Injection Zone – Injection Interval 1 (CV1) - Modeled from 2025 to 2030
2) Cotton Valley Injection Zone – Injection Interval 2 (CV2) - Modeled from 2030 to 2035
3) Cotton Valley Injection Zone – Injection Interval 3 (CV3) - Modeled from 2035 to 2040
4) Lower Hosston Injection Zone - Modeled from 2040 to 2045

Over each 5-year period a total of 2.5 million metric tons of CO_2 is injected per subzone (0.5 MMt/yr). Total time of simulation modeled for the project is 20-years (5-years per zone). The injection period in any single subzone can be extended beyond 5 years until a total injected volume of CO_2 is reached of 2.5 million metric tons, without the combined injection period in all 4 intervals exceeding the project duration of 20 years. At present, no site-specific historical data exists to calibrate the model, but will be developed as the project operates.

Results from the computational models are used to delineate an Area of Review (AoR). The AoR is defined as the area surrounding the sequestration project where the underground sources of drinking water (USDWs) may be endangered by injection operations. For the Project Blue site, this area encompasses the maximum lateral extent of the CO_2 plume (modeled) and the largest critical pressure front (Cone of Influence) preceding the plume. The largest plume extent is in the Lower Hosston (shallowest interval) and the largest critical pressure front is within the CV1 (deepest interval). Based upon the maximum extent of the pressure front, this is used to delineate the AoR. Additionally, the largest plume extent is entirely contained with the AoR pressure front. Details are discussed in Section 6.0 of this report.

The following discussions highlight each model and their impact for developing the AoR and Corrective Action Plan for the Lapis Energy Project Blue site.

2.1 MODEL BACKGROUND

2.1.1 Site Geology

Demonstration of security for injection includes a geologic containment assessment and the absence of vertically transmissive faults that could form breaches of the containment system. The Project Blue site is located in an area of minimal geological structural impacts from faults, uplifts, or domes. A stratigraphic column for the site is presented in **Figure 1**. The target reservoirs are composed of stacked shallow marine sands with interbedded mudstones. The lower injection target are the sands of the Cotton Valley Formation, which is characterized by interbedded variegated shales and sandstones. The upper injection zone is the Lower Hosston sands, which is characterized by stacked, alternating tan to white sands, with red shales. The geological structure is textbook "layer cake" with minimal dipping to the south-southwest. Most of the oil and gas production within the area surrounding the project site is located within Upper Cretaceous formations including the Tuscaloosa, Tokio, Ozan (Meakin and Graves sands) and Nacatoch. All formations which are situated shallower (less than +/-3,000 feet) than the Confining and Injection Zones for the Project Blue site. As a result, there are few artificial penetrations that extend deep enough to act as a conduit for vertical migration out of the authorized zones.

The Lower Hosston Injection Zone is overlain by approximately 890 feet of the Upper Hosston Formation, Sligo, Pine and Pine Island, which comprise the Lower Cretaceous Sequence Boundary (LCSB) Confining Zone for Project Blue. Note that the Pine Island and Rodessa Formations are successively truncated against the Lower Cretaceous Unconformity in the northern portions of the project area. The lowermost modeled Injection Interval (CV1) is underlain by the sub-regionally extensive Buckner Anhydrite Formation. This lowermost impermeable layer provides a competent lower confining unit for the sequestration project.

There are two geologic injection zones, but a total of four intervals modeled as presented below.

- Lower Hosston Sands
- Cotton Valley Sands
    - Cotton Valley CV3
    - Cotton Valley CV2
    - Cotton Valley CV1

There is one confining/impermeable zone modeled:

- Lower Cretaceous Sequence Boundary (Upper Hosston/Rodessa/Pine Island/Sligo)

These intervals are identified and in a more detailed cross-section view presented in **Figure 2** using the Schuler Drilling Company Inc. EDC No. 1 Well (AP No. 1). Please note this well is located on the EDCC facility property and will be re-entered and converted as the north In-zone (IZ) Monitoring Well as part of the Testing and Monitoring Plan.

The upper most Injection Zone is comprised of the sands of the Lower Hosston Formation, which represents the first major sedimentation event of the Lower Cretaceous period. The Hosston is characterized by red shales with interbedded white and tan sandstones, which were deposited in nearshore fluvial and deltaic environments. The next Injection Zone is the Late-Jurassic Cotton Valley Formation, which is regionally sub-divided into four units. The lowermost unit is the Bossier Shale which has a zero edge in southern Arkansas and is not found within the site AoR. The middle units of the Cotton Valley are represented by the Schuler Formation and the Hico Shale; both of which are found within the Hico lagoon of southern Arkansas. The uppermost unit of the Cotton Valley group is the Knowles Limestone which is truncated to a zero edge in southern Arkansas, like the Bossier Shale.

The sands within the Schuler formation of the Cotton Valley Formation consist of interbedded variegated shales and sandstones and are the targeted reservoirs. The deposition of the Schuler Formation was controlled by the westward transport of terrigenous sediment from longshore currents which developed an east-west barrier island complex. These barrier island complex sands comprise the three sub-divided injection intervals. The uppermost portion of the Cotton Valley consists of a greater percentage of shales as a result of sea level rise prior to the deposition of the Knowles Limestone. The Hosston and Cotton Valley sands are bounded by the shales and mudstones of the Upper Hosston (base of the LCSB Confining Zone) which are capped by an unconformity and sequence boundary.

Both injection zones are located more than 2,500 feet tvd-ss below the lowermost aquifer that meets the criteria for being a USDW (less than 10,000 mg/l total dissolves solids content), which has been identified as the Wilcox Formation. A more detailed description of the Injection Zones can be found in Section 2.3 – Site Characterization in the "*Project Narrative Report*", submitted in Module A.

2.1.2 Static Model – Petrel

Schlumberger's Petrel software was used to generate a static geocellular model, which was then imported into Schlumberger's dynamic simulation software Eclipse 100 (Ver 2019.3). Petrel was developed in Norway in 1989 by Technoguide and later acquired by Schlumberger in 2002. This software was designed to perform reservoir modeling in 3D, incorporating offset well log/core data, seismic data, and to be linked with commercially available reservoir simulators. **Appendix 2** contains model grid figures and inputs / outputs.

Petrel was selected for this project because of its easy-to-follow workflow design and because it is one of, if not the, industry leader for static geocellular modeling. It has been designed and used worldwide for reservoir evaluation and development.

Model construction begins with the definition of the model objectives. For the Project Blue site, the model objectives were to:

- Generate a 3D realization of the subsurface within a defined area that incorporates each injection interval and the corresponding impermeable overlying rock layer.

- Populate the model with key rock properties using the existing dataset and stochastic distribution. For this project, the dataset allowed for the calculation of porosity, permeability, and an estimation of the expected net sand.

- Build a model that can be evaluated through dynamic simulation using Eclipse 100, to predict the storage capacity of the selected injection intervals, and to track the expected movement of the CO_2 plume and pressure variation (increase) under the injection conditions and expected zone capacity for the interval modeled.

The identification of available data is a critical first step in model construction. This data set often includes wells, well logs, core, rock data, fluid data, and seismic. Most often the data described above is found in areas where extensive oil and gas exploration has taken place.

For the generation of the static model for Project Blue the primary data set included well logs, 2D re-processed seismic lines, and a regional data base of core. Over 129 wells were examined over a larger area of interest (county wide vs project size). Many of the wells in the study area were available through public domains such as the Arkansas Department of Environmental Quality (ADEQ) and Arkansas Oil and Gas, Drilling Info, Arkansas Oil and Gas Commission (AOGC), and the Arkansas Geological Society (AGS). Once all public data sources were exhausted, it was then supplemented with additional digital data through commercial enterprises, such as TGS or IHS (purchased licensed data). **Table 2** presents the standard well data nomenclature and the associated type of log measurements.

Table 2: Log type identification

LOG Acronym	Log Type	Unit of Measurement	Log Measurement
GR	Gamma Ray	API	Total natural gamma radiation emanating from a formation.
SP	Spontaneous Potential	Millivolts (mV)	Natural spontaneous current flow between the borehole and surface in absence of artificially applied current.
RES	Resistivity	Ohms-m	Measures a formations electrical resistivity using and an electric current. RESS – Shallow Resistivity curve RESD – Deep Resistivity Curve
DT	Acoustic/Sonic	Microseconds/ft	Measurement of compressional (primary) wave transit times through a formation.
DEN	Bulk Density	g/cm^3	Density of the formation measured by emitting gamma rays into a formation and recording the scatter back to tool
NEU	Neutron	p.u.	Measurement of porosity using the input of neutrons into the formation and measuring the reduction in energy due to hydrogen.
COND	Conductivity	Mho-m	Measures a formations electrical conductivity, the inverse of Resistivity
DPHI	Density Porosity	p.u	Porosity of formation calculated from the bulk density log using difference between bulk density values and density of formation grains and pore fluids

Log data were available as either Raster (image) or LAS (digital). For the construction of the static model LAS files were used over Raster files. There were 56 Raster images that were reviewed as part of the geologic investigation but not used in the generation of the static model. Many of the Raster images exhibit poor quality and are stretched/squeezed, which results in inaccurate structural picks when compared with LAS files. The Raster images reviewed were often near existing geographic LAS file locations. Out of the 56 Raster images, 35 did not penetrate the upper confining zone for the Project Blue site and provided no insight on the targeted Injection Zones. Therefore, the LAS files were used to generate the static model.

A total of 73 LAS files **(Table 3)** were imported into Petrel. A benefit of LAS files is that they can be used to generate properties for the static model. A total of 33 LAS files had sonic, density, or neutron curves, which enabled the calculation of properties such as total porosity.

Table 3: LAS files used in the Static Model

Well Name	API No.	Status	Logs
H.C. Armer 1S	03139002520000	P&A	SP, RESS, RESD
John Goodwin 10S	03139002780000	P&A	SP, RESS, RESD
Anthony 1B S	03139004240000	P&A	SP, RESS, RESD
Linglebach "A" 9S	03139005570000	Active	SP, RESS, RESD
Ezzell 1S	03139005590000	P&A	SP, RESS, RESD
Combs 1S	03139008320000	P&A	SP, RESD
Byrd 1S	03139009180000	P&A	SP, RESS, RESD
Stephens, EJ 1S	03139014980000	P&A	SP, RESS, RESD
Gulf 1S	03139020260000	P&A	SP, RESS, RESD
Flournoy, Scott et al 1S	03139020820000	P&A	SP, RESS, RESD
Pickering, JP 1S	03139022160000	P&A	SP, RESS, RESD
Haney 1S	03139022680000	P&A	SP, RESS, RESD, COND
Haney 2S	03139022690000	P&A	SP, RESS, RESD, COND
Parnell 1S	03139022700000	P&A	SP, RESS, RESD, COND
Haney 3S	03139022710000	P&A	SP, RESS, RESD

Well Name	API No.	Status	Logs
Haney, JA 1S	03139022720000	P&A	SP, RESS, RESD
Milner Heirs 1S	03139022730000	P&A	SP, RESS, RESD
Brasher 1S	03139022740000	P&A	SP, RESS, RESD, COND
Andress Heirs 1S	03139022750000	P&A	SP, RESS, RESD
Russell, T F 1S	03139023130000	P&A	SP, RESS, RESD
Goodwin Brewster 1S	03139044930000	P&A	SP, RESS, RESD
Goodwin Brewster 2S	03139044940000	P&A	SP, RESS, RESD
Brasher, F S 1S	03139048220000	P&A	SP, RESS, RESD
J.P. Pickering 1S	03139055550000	P&A	SP, RESS, RESD
Freeland 1S	03139055590000	P&A	SP, RESS, RESD
Goodwin Est. "A" 1S	03139055670000	P&A	SP, RESS, RESD
Whately 1S	03139103730000	P&A	SP, GR, RESS, RESD, DTC, NEU
Brashier 1S	03139104060000	P&A	SP, RESS, RESD
Long-Anthony A-3 S	03139104310000	P&A	SP, RESS, RESD, COND
*SWD BIW 5S	03139104520000	Active	SP, GR, RESS, RESD, DEN, NEU, DPHI, PHIT
*SWD 8S	03139105300000	Active	SP, GR, RESS, RESD, DEN, NEU, DPHI, PHIT
Rosen 1S	03139106500000	P&A	SP, RESS, RESD, COND
*BSW 10 S	03139108200000	P&A	SP, GR, RESS, RESD, DEN, PHIT
*Deltic Farm & Timber 11 S	03139110100000	P&A	SP, GR, RESS, RESD, DEN, NEU, DPHI, PHIT
*BSW 11 S	03139110630000	P&A	SP, GR, RESS, RESD, DEN, NEU, DPHI, PHIT
*Natural Resources 1-1S	03139110720000	Active	SP, GR, RESS, RESD, DEN, NEU, DPHI, PHIT
Hicks 1-1S	03139111360000	P&A	SP, RESS, RES
*Hammond, Iris G et al Unit 1S	03139114150000	P&A	SP, GR, RESS, RESD, DEN, NEU, DPHI, PHIT
*Saxon, C H Tr 1S	03139115030000	P&A	SP, RESS, RESD, DT, PHIT
*Wingfield 1S	03139115350000	P&A	SP, GR, RESS, RESD, DEN, NEU, DPHI, PHIT
*J&M Poultry Packing 1S	03139115770000	P&A	SP, GR, RESS, RESD, DT, PHIT
Giller 5S	03139115960000	Active	SP, RESS, RESD
Pate "A" 25 S	03139117120000	Active	SP, RESS, RESD

Well Name	API No.	Status	Logs
*Harrell 1S	03139117360000	P&A	SP, GR, RESS, RESD, DT, PHIT
*Harper, W L 1S	03139117460000	P&A	SP, GR, RESS, RESD, DT, PHIT
*Langley SWD 4S	03139117550000	Active	SP, GR, RESS, RESD, DT, PHIT
*Armstrong Est. 1S	03139118800000	P&A	SP, RESS, RESD, DT, PHIT
*McMahan 1S	03139119110000	P&A	SP, GR, RESS, RESD, DEN, NEU, DPHI, , PHIT
*Johnson 1S	03139119620000	P&A	SP, GR, RESS, RESD, DT, PHIT
*IPRC 1S	03139120730000	P&A	SP, GR, RESS, RESD, DEN, NEU, DPHI, PHIT
*Smith et al 1S	03139122150000	P&A	SP, GR, RESS, RESD, DEN, NEU, DPHI, DT, PHIT
Murphy 1-1S	03139124140000	Active	SP, RESS, RESD
*Seamster, B 1S	03139124220000	P&A	SP, GR, RESS, RESD DEN, NEU, DPHI, PHIT
Anderson 1S	03139126020000	P&A	SP, RESS, RESD,
*Goodwin, Walter 1S	03139126790000	P&A	SP, GR, RESS, RESD, DT, PHIT
Southern Hotel 1S	03139127460000	P&A	SP, RESS, RESD
*BSW 13S	03139127790000	Active	SP, GR, RESS, RESD, DEN, NEU, DPHI, PHIT
*Parnell Etal, John 1S	03139128020000	P&A	SP, GR, RESS, RESD, DT, PHIT
*Wilson Estate 1S	03139128150000	P&A	SP, RESS, RESD, DT, PHIT
*Parnell, John 2S	03139128440000	P&A	SP, GR, RESS, RESD, DEN, NEU, DPHI, PHIT
SWD 15S	03139129120000	Active	SP, GR, RESS, RESD
*SWD 16S	03139129190000	Active	SP, GR, RESS, RESD, NEU, DPHI, PHIT
WDW 5S	03139129370000	Active	SP, RESS, RESD
WDW 6S	03139129380000	Active	SP, RESS, RESD
*Mahoney Corporation 1S	03139129590000	P&A	SP, GR, RESS, RESD, DT, PHIT
*EDC 1S	03139129790000	P&A	SP, GR, RESS, RESD, DEN, NEU, DPHI, PHIT
*Dumas 1S	03139131850000	P&A	SP, GR, RESS, RESD, NPHI, DPHI, PHIT
*Murphy 1-1B S	03139131930000	P&A	SP, GR, RESS, RESD, DT, PHIT
*Frost "C" 2S	03139133030000	Active	SP, GR, RESS, RESD, DT, PHIT
*Barker 1S	03139133780000	Active	SP, GR, RESS, RESD, DT, PHIT
*Ezzell 28 Alt S	03139135060000	Active	SP, GR, RESS, RESD, DEN, NEU, DPHI, PHIT

Well Name	API No.	Status	Logs
*Pamco-Moody 2S	03139135610000	Active	SP, GR, RESS, RESD, DT, PHIT
Murphy, W R 1S	03139835660000	P&A	SP, RESS, RESD

**in total 33 wells with DT, DEN, RHOB, or DPHI, used for total porosity determination*

Note: PHIT is the total porosity curve generated from the DEN, NEU, and DPHI logs for inputs into the static model.

Regional core data was located using the Shreveport Petroleum Data Association (SPDA) and the Texas Bureau of Economic Geology (BEG) Core Databases, as well as from offset Class I wells which were requested under the Federal Freedom of Information Act (FOIA) from EPA Region 6. The data was utilized to determine porosity-permeability relationships for this project, which are detailed in Section 3.0 of this technical report.

2.1.3 Dynamic Model – Eclipse

Eclipse 100 is a Schlumberger software, which has been selected for use in this study given its specialized modeling capabilities. Eclipse is a 3D numerical simulator widely used throughout the energy and environmental industries. The software is fully thermodynamic and includes compositional Equation of State (EOS) modeling of the fluids. Eclipse provides several solvers (IMPES, Fully Implicit) and handles a variety of gridding scenarios (Cartesian, Corner Point, Curve-Linear, Radial and Core). The software provides the ability to model advective, diffuse and dispersive flow. In addition, Eclipse incorporates the United States Geological Survey (USGS) public PHREEQC database to calculate ionic and chemical reaction processes. Geo-mechanical modeling of "cap rock integrity" and/or hydraulic fracturing is also available in the software. Eclipse is a finite difference simulator with various options available for fluid modeling including water, black-oil, or compositional. **Appendix 1** [redacted]

The following static properties are generated externally to Eclipse and provided as inputs to the model using a corner-point grid format, in which grid block corners/node X/Y/Z coordinates are defined:

- Reservoir geometry (size, shape, and thickness)
- Net to Gross Ratio (Rock Types)
- Porosity
- Horizontal permeability [note: for this initial model the horizontal permeability (k_h) is set as equal to the vertical permeability (k_v)]

Eclipse accounts for the following rock and fluid dynamic processes:

- Rock and Formation Fluid Compressibility. The pressure dependence of porosity / pore space volume is modeled using a fixed rock compressibility value.

- Properties of Supercritical CO_2. Fluid properties of supercritical CO_2 such as density as a function of pressure and temperature, are modeled via the Peng-Robinson (1978) Equation of State (EOS) model.

- CO_2 Solubility in Sequestration Zone Brine. The dissolution of CO_2 into the aqueous phase is accounted for in the Eclipse Model.

- Aqueous Phase Properties. Aqueous phase viscosity and density are calculated for each reservoir based upon available data for temperature and salinity. These parameters are not set as variables in the model.

- Relative Permeability and Capillary Trapping. The relative permeability of the sequestration zone to both CO_2 and formation brine over the expected range of saturations, from 100% brine to Irreducible Water Saturation, is modeled in Eclipse using relative permeability tables.

This study models the mass injection, advective flow, and dissolution of supercritical CO_2 into an initially fully saline-water saturated reservoir using a finite difference simulator. The models include the effect of buoyant forces (gravitational effects) created by the density contrast between the CO_2 injectate and the in-situ water. The Eclipse simulator used is a Black-Oil type fluid model which allows for the variation of CO_2 saturation in brine based upon pre-defined solubility tables within the simulator; therefore, the model is not compositional, and dissolution (solubility trapping) is based upon the constitutive relationship defined between CO_2 and the formation brine respectively.

The model does not yet incorporate dispersion and diffusion, thermal variations within reservoirs or throughout time, mineralogical transformation, salt deposition, or hysteresis of relative permeabilities and capillary pressures. However, the model does include a critical CO_2 saturation (S_{cr}) of 5% but assumes no differential between residual CO_2 saturation (S_{gr}). Therefore, in the simulation model, the S_{gr} during imbibition is equal to the S_{cr} during drainage.

CO_2 and brine properties were generated for a fixed temperature in each reservoir respectively. CO_2 density is estimated using Eclipse's implementation of the Peng-Robinson (1978) EOS. Eclipse solves the equation by taking the pressure, temperature, and the starting composition of a grid cell. It then provides the composition of each of the two possible phases in which the fluid might exist, either a gaseous and/or an oleic (oil) phase for that cell. The mole density (number of moles per unit volume of the phase) is also calculated. The Lorenz, Bray Clark method is used to estimate CO_2 viscosity by calculating the gas viscosity based upon the composition of the gas.

Regarding the finite difference method, there are many publications that offer very detailed explanations of how this method is implemented. [redacted] **Appendix 1** of this study.

2.2 MODEL DOMAIN

The static model covers an area of approximately 195 mi^2 (70,000 x 80,000 feet) and was constructed to encompass the Project Blue site, and the Lanxess Class I injection site to the south (both in Union County as presented in **Figure 3). Figure 4** shows the skeleton grid in 3D and the model domain information is summarized in **Table 4.**

Table 4: Model domain information

Coordinate System	SPCS27_1701: NAD27 Arkansas State Planes, Southern Zone, US Foot		
Horizontal Datum	Mean Sea Level (MSL)		
Coordinate System Units	Feet-US		
Zone	Arkansas State Planes South		
FIPSZONE	0302	**ADSZONE**	3251
Coordinate of X min	1749200	**Coordinate of X max**	1829200
Coordinate of Y min	183250	**Coordinate of Y max**	255250
Elevation of top of domain	-2,566	**Elevation of bottom of domain**	-7,473

The corner point grid created in Petrel was exported in "Eclipse ASCII format" and imported into Eclipse dynamic simulation software. The grid has 57 cells in the X direction, 57 cells in the Y direction, and 1,318 total layers. Cell block dimensions in the x-y vary based upon the distance from the Project Blue Injection Well. Within a 1-mile boundary of the Injection Well, the x-y cells are 500 x 500 feet and at the boundaries of the model the cells are 4,000 x 4,000 feet respectively **Figure 5**. Cell block height varies between confining intervals and injection intervals the corresponding cell block heights are 10 feet and 2 feet respectively.

[redacted]

[redacted]

The origin (cell block 1,1,1) in Eclipse is in the upper left (Northwest) corner of the grid. Layer 1 is the shallowest layer. Depth increases with each subsequent layer number. Layer dimensions are measured in feet (ft) and vertical distance is measured in True Vertical Depth (TVD) relative to sea level (tvd-ss).

The upper left corner of the origin cell (1,1,1) corresponds to geospatial coordinates of 1751282 easting, 254133 northing using NAD27 South - Arkansas State Plane coordinates. The grid extends horizontally 74,721 ft and 71,849 ft vertically. The geospatial coordinates of the southeast corner of the grid, cell (57, 57, 1), are 1825974 easting and 253922 northing.

2.2.1 Static Model Layers

The static model construction begins with the generation of the framework. For the Project Blue site, no faults were identified within the affected area. This was confirmed during a review of reprocessed 2D seismic data (Confidential Business Information (CBI)) and from a thorough review of commercially available structure maps (*i.e.*, Cambe Geomap, which is also CBI due to licensing) for the project area.

Model construction began with the correlation of four key stratigraphic intervals: LCSB Confining Zone, the Lower Hosston, Cotton Valley, and Buckner formations. These four stratigraphic intervals were converted to structured surfaces in Petrel using well tops as the foundation. For the Buckner horizon, additional control was provided from 2D seismic correlation picks. These Structured Surfaces (or Horizons) are presented in **Appendix 3**. Due to the overall thickness of the Injection Zones, and the project objective to control maximum plume extent, further subdivision of these intervals was employed. Therefore, flooding surfaces within both the Hosston (Lower Hosston) and Cotton Valley (intervals 3, 2, and 1) zones were correlated and added to the model as Horizons. These surfaces were input into the model construction workflow, using a simple grid function in Petrel. This yielded a total of eight Horizons which compose the major framework of the model **Appendix 3**.

To capture as much detail in the vertical resolution of the rock type (facies) variation as possible, the vertical layering within the injection intervals was set at an average of 2 feet while the vertical layering in the confining (impermeable) zones was set at 10 feet. The layers are summarized in **Table 5.** An intersection window of the detailed vertical layers can be seen in **Figure 6**.

Table 5: Static Model layering

Formation	Model Purpose of the Formations/Horizons	Horizon Number	Average Gross Thickness Between Horizons	Number of Static Model Layers	Average Gross Layer Thickness at the Wells (feet)
Lower Cretaceous Sequence Boundary	Top of the Model Horizon/Confining Unit	1	470	1-47	459
Mid Lower Cretaceous Sequence Boundary	Confining Unit	2	450	48-92	451
Lower Hosston	Injection Interval	3	560	93-372	575
Cotton Valley	Confining Unit	4	480	373-420	552
CV3	Injection Interval	5	650	421-745	530
CV2	Injection Interval	6	420	746-955	392
CV1	Injection Interval	7	330	956-1120	343
Buckner	Model Base (Confining)	8	-	-	-

Layering derived from the static model is transformed for use in two independent dynamic models, one for each of the proposed injection intervals. Each formation had an average gross layer thickness (in feet), that was then equally divided into the modeled layers.

2.2.1.1 Lower Hosston Injection Zone

The overlying LCSB Confining Zone represents layers 1-92 in the Petrel static model. The muds and shales of the LCSB are assumed to mitigate the vertical migration of CO_2. The confining layers 1-92 have an average thickness of 920 feet with each layer being assigned a thickness of 10 feet each in the model.

The Lower Hosston sands targeted for injection are represented by layers 93-372 with a total average thickness of 560 feet with each layer being assigned a thickness of 2 feet each.

2.2.1.2 Cotton Valley Injection Zone

The Cotton Valley Injection Zone has been subdivided into three independent modeled intervals. (CV1, CV2, and CV3) with the uppermost portion of the formation as a fourth layer, represented as a containment unit. These sub-zones are represented in layers 373-1120, with a total average thickness of 1,880 feet (for formation). The uppermost containment layer has a regionally consistent decrease in the net to gross (less sand). These layers (373-420) were given a thickness of 10 feet each. Each of the three sub-zone injection intervals display average thicknesses between 350 and 500 feet respectively. The three injection intervals of the Cotton Valley represent layers 421-1120 and have a thickness of 2 feet each in the model.

The Cotton Valley sands are underlain by the basal horizon of the model, which is represented by the Buckner Formation. It is characterized as an anhydrite and recognized as a regional seal for the underlying Smackover Formation.

3.0 MODEL INPUT AND SOURCES

Multiple sets of data were used to evaluate and determine parameter inputs in the models for the Project Blue CCS Site. Data sets included available offset well logs, that are of sufficient quality, purchased and project specific reprocessed 2D seismic lines from Seismic Exchange Inc and Bailey Banks Seismic LP, available local core representative of the Lower Hosston and Cotton Valley Formations, including core analyzed specifically for the purpose of this project, and published literature sources. Conservative assumptions were made when data was insufficient. The data limitations will be resolved with the drilling and testing of the Injection well and this data will be incorporated into future model iterations.

As discussed in Section 2.1.2, 73 logs were evaluated to build the static model for the Project Blue site and are presented in **Table 3.** Petrophysical properties such as grain density, porosity, and permeability were calibrated using regional core data available from the SPDA and the Texas BEG **(Table 6). Figure 7** shows the locations from where available core was used in the analysis.

Two rock types were model for the Project Blue Site, which are sand and shale. The methodology employed to determine the rock types (facies) was a sand cutoff using the shale volume (Vsh) approach. Although, the Buckner Formation is an anhydrite, it was deemed unnecessary to model this specific rock type, because it is the basal layer of the model. It will not take flow and has not been modeled for property distribution. For simplicity in the model, a two-rock type approach was maintained.

Table 6 – Available core data for analysis

API Number	Well Name	Number of Samples	Depth Range (feet)
Injection Zone 1 – Lower Hosston			
03-139-00028-0000	C.A. Langley 1 S	2	3105-3277
03-139-10119-0000	Ezzell 27 S	2	3830-4705
03-139-11038-0000	Tarver-Ezzell 1 S	3	3263-3268
03-139-11301-0000	Craig, H G 1 S	13	3370-4142
03-139-11455-0000	Alphin 1 S	3	4138-4142
03-139-11765-0000	Craig, H.G 1 S	11	3370-3376

API Number	Well Name	Number of Samples	Depth Range (feet)
03-139-11835-0000	Sandifer 1 S	8	3363-3371
03-139-12182-0000	Timmins 1 S	3	3114-3128
03-139-12255-0000	Langley 2 S	11	3081-3978
03-139-12279-0000	Langley 3 S	27	3040-3809
03-139-12312-0000	Williams 1 S	11	3080-3561
03-139-12337-0000	Gulf Mineral Fee/Clark 1-7 S	22	3170-3851
03-139-12361-0000	Triangle Ind. 2 S	8	3765-4033
03-139-12529-0000	Triangle 1 S	20	3286-3693
03-139-12722-0000	J.T Murphy 1 S	5	3861-3866
03-139-12750-0000	Mitchell Estate 1 S	14	3031-3070
03-139-12875-0000	Hinshaw 1 S	14	3391-3619
03-139-12937-0000	Waste Disposal Well 5 S	225	3679-5078
03-139-12938-0000	Waste Disposal Well 6 S	97	3760-5192
03-139-13054-0000	Rosen “B” 1 S	3	3194-3311
03-139-03544-0000	Bishop No. 1*	7*	3929-3954*
Injection Zone 2 – Cotton Valley			
03-139-02271-0000	Haney 1 S	5	6537-6541
03-139-03417-0000	Edson 1S	32	7536-7602
03-139-10119-0000	Ezzell 27 S	22	5004-5960
03-139-11166-0000	Hogg, James 1 S	34	5365-6878
03-139-11455-0000	Alphin 1 S	1	6573
03-139-11502-0000	Mekins, Franklin F 1 S	1	5147
03-139-11765-0000	Craig, H.G 1 S	14	4138-6030
03-139-11766-0000	Clark, O.B 1 S	6	4333-4359
03-139-13054-0000	Rosen “B” 1 S	16	3537-4430

BEG core that is currently undergoing testing with Stratum Labs. Samples were selected by Geostock Sandia and Lapis Energy subsurface teams to calibrate existing SPDA core

3.1 SHALE VOLUME

Potential injection or seal units are first identified using a shale volume estimate. The Vsh estimate effectively normalizes a combination of electrical logs with responses primarily associated with lithological changes:

- Gamma Ray log, which detects the natural radioactivity of the minerals,
- Spontaneous Potential log, which measures small electrical potentials at each depth between the formation and a grounded electrode at the surface,
- Bulk Density log, which uses gamma ray scattering using a radioactive source and a single detector. The measurement is a result of the grain density of the varying minerals and the pore space. The combination of bulk density and neutron (*i.e.*, measures the hydrogen count in the formation) or sonic logs (*i.e.*, measures the compressional velocity, impacted by mineralogy) enables the differentiation of the lithology.

Shale volume estimates (which generates sand volume estimates) for the Lower Hosston and Cotton Valley were used to identify the permeable strata by using the GR and SP logs. However, identification of shale volume using the SP logs is limited to wells with conductive borehole fluid (*i.e.*, water-based muds and saline brines) and sparse insufficient GR log coverage. Permeable strata were also identified using the deep Resistivity curves from Laterolog or Induction tools (tools applied depending on the drilling mud type). These tools are used to measure the electrical conductivity in the formation and, through different petrophysical models, the formation saturation. An increase in resistivity values can be indicative of hydrocarbons, a lower total dissolved solids (TDS) content in the formation, and impermeable layers. The range of clay electrical conductivity is relatively constant (depending on clay type) and associated to the intrinsic clay bound water and salinity. In brine saturated formations there is lower uncertainty associated with the fluids in the pore system, therefore variations in conductivity can be associated with textural characteristics such as grain size, pore volume, and pore throat size.

To determine the sand/shale cutoff in the Lower Hosston and Cotton Valley the mudstone baseline was determined in a two-step process. First, a smoothing of the SP curve over a 50-foot interval throughout a log, to decrease the noise from high frequency deflections in the permeable beds.

Secondly, a sand count log was created where the deflection of the SP log was more than 10 millivolts less than the mud baseline. The results of this two-step process are presented in **Figure 8** using the ECD No. 1 (AP No. 1) as an example. This is shown in the shaded yellow portion in the SP log, as well as the facies log displayed to the right.

Without site specific calibration, the sand cutoff is used only as a qualitative indicator of permeable zones, therefore no corrections were applied. The results from the SP baseline determination were then upscaled in the static model for the two rock types (sand and shale). **Appendix 4** documents the wells used, data analysis, property cube, histograms, and facies distribution maps.

3.2 POROSITY

Porosity is defined as the ratio of void space to the total bulk volume of rock. It is expressed as a percentage (Amyx et al., 1960). There are different porosity types, traditionally siliciclastic systems deal with primary intergranular porosity (*i.e.*, the void space that is preserved between the grains as a result of the fluid content), but complex porosity types (*i.e.*, secondary porosity) exist as a result from dissolution and other mineral altering processes in carbonate systems, among others. Intergranular porosity is subdivided into the macro porosity space as well as a micro porosity space.

The porosity type is highly dependent on the mineral composition of the rock and defines how much effective pore volume is accessible to reservoir fluids. Primary intergranular porosity results from preservation of pore space after deposition and lithification of sediments. Microporosity, which is associated with clays, is present in the matrix and greatly affects the volume of effective porosity accessible to reservoir fluids. The macro porosity space is the volume accessible to fluids, the micro porosity space is filled with clay bound water as well as capillary bound fluids. Porosity is the ratio of pore volume to the total volume of the rock and accounts for all porosity types, whereas effective porosity is the ratio of interconnected pore volume to the total volume of rock, in siliciclastic systems it is traditionally the macro porosity space. When modelling porosity, the decision must be made to model total porosity or effective porosity. Since there is a high level of uncertainty in calculating effective porosity from wireline log data and in measuring effective porosity in cores, we have decided to model total porosity.

The following sections detail the available data sets, method for determining the porosity for the injection zones, and the numerical assignment within the model.

3.2.1 Data Sets

Multiple sets of data were used to evaluate and characterize the porosity for the Project Blue site. Data sets included regional offset well logs, regional core, and published literature sources. Log data for total porosity calibration, that had density and/or sonic logs, was available for 31 logs (**Table 3 and Figure 9**) using the DT, DEN, RHOB, and DPHI curves.

Please Note: Site specific data will be collected during the drilling and testing of the Injection Well for the targeted injection zones. Core analysis will include porosity and permeability measurements. Details are contained in the "*Pre-Operational Testing and Logging*" plan contained in **Module D**. Future model iterations will be refined using the data collected from the injection well.

3.2.2 Methodology

Logs were uploaded into Techlog©, which is an integrative software program available from Schlumberger. This software program was developed to allow the user to evaluate and interpret well log data and integrate core data. The software allows comparison of the mathematical models with calibration data such as core, well tests, formation and fracture pressure measurements, among others. The results are exported in a digital format, compatible with the static and dynamic modelling packages.

Ideally, the static model should contain effective porosities as an estimate of representative volume accessible to fluids. However, effective porosity quantification requires calibration obtained from Nuclear Magnetic Resonance (NMR) measurements. In the absence of NMR data, effective porosities can be estimated from shale volume content with a large degree of uncertainty given that the clay type influences the degree of clay-bound and capillary-bound volumes. Due to limited sample measurements and advanced log availability, total porosity values are used in the model and discounted by using a saturation height function, derived from capillary pressure measurements.

Thirteen bulk density logs, fourteen sonic logs, two DPHI logs and four wells with both bulk density and sonic were available for analysis near the Project Blue site (see **Table 3 –** DT, DEN, RHOB, and DPHI curves). Porosity from density is considered the most representative estimate of the property in a formation, followed by the sonic porosity estimate. Sonic porosity estimates require additional calibration introduced by fluid content as the measurements are affected by the grain framework, as well as the saturating fluids (to a larger extent). Porosity estimate from neutron logs are not considered individually representative as clay bound water introduces excess porosity due to its hydrogen response. The clay bound water is part of the clay matrix structure, and although it appears as part of the total porosity, it is pore space that is inaccessible to fluids. Therefore, it is not part of the effective pore volume.

The most representative porosity estimate is obtained from the bulk density log, as the measurement is equally sensitive to the matrix and fluid content, however, sonic porosity estimates were performed where density logs were unavailable. The bulk density log captures porosity variations by depth within the invaded zone in the wellbore. A matrix density and fluid density are used to calculate porosity using the density porosity equation below.

$$\varnothing_{density} = \frac{\rho_{matrix} - \rho_{bulk}}{\rho_{matrix} - \rho_{fluid}}$$

Where:

$\varnothing_{density}$ total porosity

ρ_{matrix} mean density of the matrix minerals

ρ_{bulk} bulk density

ρ_{fluid} density of the fluid

Matrix density (based upon core grain density measurements) is estimated to be on average 2.64 g/cm^3 for sandstones in the Lower Hosston and 2.65 g/cm^3 for sandstones in the Cotton Valley, where data was available (**Appendix 5)** . A fluid density of 1.00 g/cm^3 was used for the Lower Hosston and the Cotton Valley.

Log porosity estimates were also performed using the Raymer Hunt equation applied on fourteen available sonic logs. This method employs reference matrix compressional slowness values (whether sand or shale) obtained from analogue measurements. The constant factor C was tailored for the Lower Hosston and Cotton Valley formations using the density as reference (when both logs were available).

$$\emptyset_{sonic} = C\,\frac{\Delta t_{log} - \Delta t_{matrix}}{\Delta t_{log}}$$

Where:

$\emptyset_{sonic}$	total porosity
C	0.625 (also represented as 5/8) constant factor
Δt_{log}	sonic response at depth of interest
Δt_{matrix}	response associated with matrix

Sonic logs analysis is dependent on estimating the formation pressures and the compressibility of the material. As these site-specific parameters are estimated, the total porosity values from the sonic logs are considered conservative.

Additionally, porosity measurements from available core were obtained from the SPDA regional database to calibrate the total porosity logs. The minimum and maximum core porosity measurements are used to validate assumptions in the distribution used for the static model (**Table 7**).

Table 7: Total porosity measurements from available core

Formation	Minimum Porosity*	Average Porosity*	Maximum Porosity*
LCSB Confining	2.1 %	6.8 %	12.9 %
Lower Hosston	13.0 %	23.7 %	37.3 %
Cotton Valley	9.0 %	21.6 %	36.9 %

Additionally, core porosity measurements were performed on core from the Bishop No. 1 well (supplied from the BEG Houston) to validate the log porosity estimates used in the modeling of the Lower Hosston injection zone (**Table 8**).

Table 8: Additional measurements performed in Bishop No. 1 well (BEG core)

Formation	Sample Number	Sample Depth (ft)	Porosity (%)	Grain Density (g/cm^3)
Lower Hosston	1-1H	3,928.4	18.6	2.66
Lower Hosston	1-2H	3,929.2	30.7	2.64
Lower Hosston	1-4H	3,938.4	31.1	2.65
Lower Hosston	1-6H	3,945.6	27.4	2.65
Lower Hosston	1-8H	3,946.3	27.9	2.64
Lower Hosston	1-10H	3,953.3	28.5	2.64
Lower Hosston	1-12H	3,954.0	28.3	2.64

The porosity values obtained from the Bishop No. 1 well are in good agreement with the SPDA values used to validate the parameters used in the static model. Total porosity in the shales is expected to range between 15% above the Lower Hosston and 9% for the interbedded shales within the Cotton Valley.

3.2.3 Porosity Modeled

The well log data was first upscaled at the well location within the model layering. A detailed workflow for how the porosity was assigned in the model and distributed is in **Appendix 5** of this report. The porosity logs for each of the Injection Intervals (Lower Hosston and Cotton Valley) were upscaled using a "simple arithmetic average", with the log data sampled by treating the log as lines and "neighbor cells". The data from the upscaled well logs was then distributed within the model utilizing a simple sequential gaussian simulation.

Appendix 5 presents the histograms of the total porosity data in three states: 1) that of the raw well log data; 2) the range in the upscaled cells; and 3) the range in the model populated property. Over the Lower Hosston Injection Interval, the histogram shows that the total porosity well log data spans a range of 0.0% to 43.0%. with an average of 20.0%. For the Cotton Valley Formation (as a whole) the total porosity well log data spans a range of 0.2% up to a maximum of 57.7%, and an average of 18.7%. For the CV3 Injection Interval, the total porosity well log data spans a range of 0.4% up to a maximum of 57.2%, and an average of 17.1%. For the CV2 Injection Interval, the total porosity well log data spans a range 0.0% up to a maximum of 48.8%, and an average of 16.8%. For the CV1 Injection Interval, the total porosity well log data spans a range of 2.8% up to a maximum of 39.4%, and an average of 15.3%. All the data for these injection intervals can be found in the tables accompanying the porosity data histograms (**Figures 2 to 6 in Appendix 5**).

This wide data range is the result of using total porosity, as there is not sufficient data to calculate an effective porosity at this time. Appropriate data will be collected so that an effective porosity can be calculated with the drilling and testing of the Project Blue Injection Well and used in future model iterations.

Through the process of upscaling, the range of porosity values over the injection intervals is refined. Upscaling is done using the same method in both confining and injection units; however, the cell layers are 10 feet and 2 feet; respectively. With the thicker vertical layering there will be a more dramatic smoothing and/or tightening of porosity ranges in the confining intervals. Due to the presence of interbedded shales the range of porosity values for each of the targeted intervals is wide. It should be noted that while the porosity distribution in the Lower Hosston Injection Interval yielded what appeared to be a relatively normal distribution, the Cotton Valley Injection Intervals indicate the possibility of a bimodal porosity distribution. This will be further evaluated with the site-specific data acquisition from the Project Blue Injection Well.

For populating the model with total porosity, the specific variogram settings can be found in **Figures 8 through 12** (contained in **Appendix 5)** for each interval. For all layers, total porosity was modeled using "*Gaussian random function simulation"*.

The spatial variability of the porosity is laterally heterogenous as is indicated by the porosity distribution maps that represent each layer in the static model (**Figures 10 through 16**). Note that in general the porosity decreases to the south and west as depth increases. **Table 9** contains the porosity inputs into the model based upon the conservative analysis.

Table 9: Porosity inputs into the Static Model by layer

Model Layer	Min Porosity (%)	Max Porosity (%)	Average (%)
LCSB Confining Zone			
1-92	0	42.6	27.2
Lower Hosston Injection Zone			
93-372	0	40.7	20.1
Upper Cotton Valley Containment Unit			
373-420	0.004	41.9	0.1924
CV3 Injection Interval			
421-745	0.002	41.5	17.5
CV2 Injection Interval			
746-955	0	43.9	16.8
CV1 Injection Interval			
956-1120	0	40.2	15.5

The porosity values in the LCSB are elevated due to the presence of sands that come and go through the section due to the regional unconformity. The porosity logs created in Techlog reflect these changes in porosity across different rock types and this is captured in the static model.

Initial data indicates that the top of the Lower Hosston Injection Zone contains the highest average porosity, with porosity decreasing with depth to the CV1 Injection Interval.

There is one impermeable zone modeled, the LCSB impermeable confining unit. For all additional containment intervals, the porosity is documented as discussed above from well log to upscaling and property modeling. The main constraint for porosity and permeability in the confining intervals is the change in the predominant facies being shale. It is worth noting that the LCSB Confining Zone does display a higher porosity than the lower injection units; however as will be discussed in the permeability section, there are more lithologic variabilities.

3.3 PERMEABILITY

Permeability is defined as the capacity of a porous media to transmit fluids (Amyx et al., 1960). High connectivity of the pore spaces provides the pathway for fluids or gases to move through a formation, in either direction (vertical or horizontal). However, permeability is not an intrinsic rock property and varies depending on multiple factors such as the fluid content and textural components such as grain size, orientation, arrangement, cementation, clay content, grain size distribution and sorting. When two or more fluids are present within the pore space, immiscible displacement of one fluid by another affects the speed at which each fluid flows within the porous space (*i.e.* relative permeability). Immiscible displacement of brine takes place when CO_2 is injected into an aquifer in addition to the interaction of the brine and CO_2 (dissolution of one phase into another depending on the pressure and temperature conditions).

Absolute permeability is a function of porosity, irreducible wetting phase saturation, displacement or threshold pressure corresponding to a pore throat radius, and basic pore size characteristics. Since porosity dominates the pore size characteristics more than any other textural component, a porosity-permeability correlation can be used to estimate permeability from total log porosity for each injection zone.

3.3.1 Methodology

Absolute permeability is described by Darcy's Law. Calibration can be obtained from a range of sources: core measurements (plug scale), NMR (log resolution), formation pressure mobilities (connected flow units), drill stem tests, and formation transient analysis from ambient pressure falloff tests (zones open to testing for flow). The following equation is an adapted form of Darcy's Law, which assumes no gravitational forces and a homogeneously permeable medium:

$$Q = -\frac{kA}{\mu}\frac{dp}{dL}$$

Where:

Q = volumetric flow in cm^3/s

k = permeability in Darcy

A = cross-sectional area in cm^2

μ = viscosity in cP

dp/dL = Pressure drop per unit length in atm/cm

Often core permeability measurements result in a wide range of absolute permeability values per porosity class. The range of permeability variations observed in each porosity class can be explained by variations in mineralogy, facies, and clay type. This can be addressed by rock typing where sufficient calibration data is available. Regional core (total) porosity and permeability data were obtained from multiple data sources (*i.e.*, BEG and SPDA) **(Table 6)** which were then used in the calibration.

The data was integrated with the static model to define mathematical functions representative of average permeability values (**Appendix 6**). Additional core for the Lower Hosston Injection Zone was available from a nearby offset well (Bishop No. 1). Lapis Energy was able to view and select the core from the BEG, and have additional testing performed by Stratum Labs. Results are presented in (**Appendix 6**). Absolute permeabilities are distributed in the static model and are later supplemented with relative permeability functions in the dynamic model to simulate the CO_2-Brine flow.

For the sand facies in the injection reservoirs, a porosity-permeability transform (**Table 10**) was developed and used to build a permeability property cube in the static model (see **Appendix 6**).

Table 10: Porosity-Permeability Transforms used in the static model.

Injection Zones (Reservoirs)	Porosity-Permeability Transform
Injection Zone 1 – Lower Hosston Sands	$K_{abs} = 2E - 8 * \varphi^{(7.4318)}$
Injection Zone 2 – Cotton Valley (*all intervals*)	$K_{abs} = 0.0056 * \varphi^{(2.9143)}$

For the shales, the permeabilities were fixed at 0.001 mD. The justification for assigning a specific permeability value for the shales in the Lower Hosston and Cotton Valley Injection Intervals is based upon core reports gathered during the FOIA request of the Lanxess (*formally Great Lakes)* Class I Injection Wells. **Table 11** presents permeability data for the (upper and lower) Hosston shales.

Table 11: Porosity and Permeability data from regional core data

API Number	Well Name	Number of Samples	Depth Range (ft)	Avg Porosity (%)	Avg Perm (mD)
Shales of the Hosston Formation					
03-139-12937-0000	WDW005	45	3,679 – 3,927	4.61	0.0954
03-139-12938-0000	WDW006	12	3,780 – 5,149	10.3	0.0425

Note: 75% of the shale samples in WDW005 and 40% of the samples in WDW006 have reported permeabilities of <0.01 millidarcy indicating that the permeability is below this value but not discernable with the permeability testing equipment of the lab

Additionally, permeability data for the Midway Shale was available from WDW003 with an average of $1x10^{-4}$ mD. This is used as secondary justification for the permeability values used for the shale units (**Figure 17**).

Lapis Energy conducted routine core analysis on samples selected from the core viewed at the BEG with the aim to confirm the data obtained from the SPDA. **Table 12** demonstrates the results from porosity and permeability in the Lower Hosston Injection Zone collected from the Bishop No. 1 well. The results from the recent core test fit the trends used to model porosity and permeability in the static model. **Figure 18** presents where the newly collected core data fits with the data used to predict porosity and permeability in the model are shown in **Appendix 6.**

Table 12: Porosity and Permeability data from Bishop No. 1 core data

Formation / Well	Sample Number	Sample Depth (ft)	K_air (mD)	K_klink (mD)	Phi at 800 psi (%)
Hosston - Bishop (03544)	1-1H	3,928.4	21	17	18.6
Hosston - Bishop (03544)	1-2H	3,929.2	723	683	30.7
Hosston - Bishop (03544)	1-4H	3,938.4	745	704	31.1
Hosston - Bishop (03544)	1-6H	3,945.6	295	273	27.4
Hosston - Bishop (03544)	1-8H	3,946.3	320	296	27.9
Hosston - Bishop (03544)	1-10H	3,953.3	313	289	28.5
Hosston - Bishop (03544)	1-12H	3,954.0	443	413	28.3

3.4 ROCK COMPRESSIBILITY

If the pressure in a formation increases, such as due to injection, or drops, such as due to fluid withdrawal, the skeletal matrix will expand or contract, respectively (Fetter, 1988). This elasticity in the skeletal matrix is known as bulk compressibility (Fetter, 1988). Bulk Compressibility is a material property that describes the change in volume induced in the material by an applied stress. Individual components (*e. g.* grains and fluids in the pore space) interact in a way that distribute stresses in the system by expanding or contracting. Individual compressibility values (grain and fluid) depend on rock and fluid type.

Petroleum engineering generally handles three-phases being present within a formation. Therefore, total compressibility when there are three fluid phases is defined as:

$$c_t = c_f + S_o c_o + S_w c_w + S_g c_g$$

where:

c_t = total or bulk compressibility (psi^{-1})

c_f = formation or grain compressibility(psi^{-1})

S_o = oil saturation (fraction)

c_o = oil compressibility (psi^{-1})

S_w = water saturation (fraction)

c_w = water compressibility (psi^{-1})

S_g = gas saturation (fraction)

c_g = gas compressibility (psi^{-1})

3.4.1 Formation Compressibility

For water-filled reservoirs, such as at the Project Blue site, in which S_w equals 1, this simplifies to:

$$c_t = c_f + c_w$$

The change in porosity is a result of the elastic properties (or moduli) of the framework of the rock (*i.e*. the grain, cements and contacts). A large pore volume compressibility transfers pore pressure more effectively across the pore system, enabling fluids to percolate through. The rate of change in pore volume is influenced by textural components of different rock types. It is quantified by pore volume compressibility (c_f).

The Lower Hosston and Cotton Valley are consolidated formations with expected compressibility ranges between $3x10^{-6}$ and $5x10^{-6}$ $psi^{-}1$; respectively. These formation compressibility values were estimated using Yale's correlation (Yale et al., 1993):

$$c_f = A(\sigma - B)C + D$$

where parameters A, B, C and D are obtained from literature for a range of rock types and sigma is (where K indicates the directional load):

$$\sigma = K1*[\text{overburden stress gradient} * \text{depth}] - K2 * pi + K3 * (pi - p)$$

The Hosston and Cotton Valley are considered consolidated sands based on the cores examined. The parameters and constants used were obtained from literature (Yale et al., 1993) and are summarized in **Table 13.**

Table 13: Yale variables and constants for consolidated sands

Parameter	**A**	**B**	**C**	**D**
Yale Variables	$-2.399x10^{-5}$	300	0.06230	$4.308\ x10^{-5}$
Parameter	**K_1**	**K_2**	**K_3**	
Yale Constants	0.85	0.80	0.45	

Compressibility inputs into the model for the injection zones used for the model are contained in the following table:

Table 14: Compressibility for the Injection Zones

Injection Zones	Formation Compressibility (psi^{-1})
Injection Zone 1 – Lower Hosston Formation	4.47×10^{-6}
Injection Zone 2 – Cotton Valley Formation *(all intervals)*	3.75×10^{-6}

Future data and calibration for compressibility will be obtained from testing of the core material. Calibration is obtained as part triaxial tests on vertical samples, which are designed to estimate the Biot coefficient (*i.e.* the fluid volume change induced by bulk volume changes in the system). To measure bulk compressibility, the vertical sample is loaded isostatically and a constant pore pressure is applied, changing the effective stress on the sample. Strains are monitored and used to estimate volumetric strain. These measurements for total bulk compressibility will be used to reduce uncertainties for the overall compressibility of the material. It will also provide refinement into the model.

3.4.2 Formation Fluid Density, Compressibility, and Viscosity

Density

The formation fluid density used in the model was obtained from nearby offset well samples and data. The formation fluid density yields a pressure gradient that trends with the highest gradient values observed in the regional pressure data.

Table 15: Brine Properties used for input into Eclipse 100 model

Injection Zones	Brine Salinity (ppm)	Brine Density (lb/ft^3)
Injection Zone 1 – Lower Hosston Formation	170,057	70.3
Injection Zone 2 – Cotton Valley Formation *(all intervals)*	209,004	72.2

Brine properties at standard conditions (P=14.7 psi, T=60F) are calculated by McCain correlation for the salinity values give

The brine density at reservoir conditions additionally depends on reservoir temperature, pressure, and CO_2 to Brine solution ratio (Rs).

The estimated *in-situ* brine density used in the model is developed as a function of Rs and brine formation volume factor (determining reservoir density) based upon the method described in Hassandzadeh et al (2008).

Compressibility and Viscosity

Brine compressibility (c_b) represents the change in volume (∂V_b) of the brine, relative to initial volume (V_b), for a given pressure change (∂p) at constant temperature.

$$c_b = \left({}^{1}/_{V_b} \right) \left({}^{\partial V_b}/_{\partial p} \right)$$

Compressibility can also be defined based on the change in density (∂V_b) of the brine, relative to initial density (ρ_i), for a given pressure change (∂p) at constant temperature, assuming mass is conserved.

$$c_b = \left({}^{1}/_{\rho_i} \right) \left({}^{\partial \rho}/_{\partial p} \right)$$

In general, a larger density difference between the in-situ fluid and injected CO_2 increases the predicted plume size, and buoyancy velocity. Velocity of the CO_2 phase can be estimated analytically using the equation below.

$$U = \Delta\rho g k \,/\, \phi\mu l$$

In the equation, U = Darcy velocity due to buoyant force, $\Delta\rho = \rho h - \rho l$, is the density difference between the heavy (brine) and light (CO_2) phase, g is the gravitational constant, $k/\mu l$ is the mobility of the light phase and ϕ is the porosity.

Note that, within each target reservoir, a constant-salinity isothermal initial condition is assumed; that is, salinity and temperature do not vary with depth. In contrast, initial pressure within each reservoir does vary with depth. During model initialization, pressure is extrapolated from the starting pressure and reference depth using a depth-dependent brine density.

Viscosity is a measure of a fluid's resistance to flow. For the purpose of constructing the initial CO_2 sequestration model (without yet having the site-specific PVT data available), formation brine viscosity at subsurface conditions is estimated using a Microsoft EXCEL spreadsheet correlation as a function of pressure, temperature, and NaCl content developed by Douglas M. Boone in 1993.

Table 16: Initial brine compressibility and viscosity at nominal conditions

Zone	Brine Salinity (ppm)	Temperature (F°)	Brine Compressibility (1/psi)	Brine Viscosity (cP)
Lower Hosston	170,057	134	2.23×10^{-6}	0.808
Cotton Valley	209,004	144	2.13×10^{-6}	0.793

As expected, viscosity decreases with depth since the formation gets hotter. However, this tendency to decrease may be impacted in intervals exhibiting higher salinities. In these zones, the formation water gets thicker and more viscous, having an inverse effect. These initial viscosity values are based upon no site-specific data and assumptions are made for the site-specific salinity and temperature based on regional data. Viscosity of the formation fluids will be evaluated at the time of analysis. The site-specific data on the formation fluid will be used to refine the static and dynamic simulation model, as well as to refine the geochemical modeling.

3.4.3 Dissolution of CO_2 in Brine

Dissolution of CO_2 in brine is one of the trapping mechanisms which was modeled in the dynamic simulation for Project Blue. Eclipse 100 is a non-compositional model, therefore in order to model dissolution a "Black-Oil" approach was taken. For this approach, pre-defined tables of solubility versus pressure are input into the Eclipse database for each reservoir. At each timestep of CO_2 injection, Eclipse references these tables to determine the amount of CO_2 dissolved into the brine as a function of pressure.

Solubility of CO_2 in brine at reservoir conditions is defined by the CO_2 to Brine ratio (Rs):

$$Rs = \frac{(V_d * CO2_{sc})}{(V_{bsc})}$$

Where:

V_{dCO2sc} is volume of dissolved CO_2 in formation brine at standard conditions

V_{bsc} is formation brine volume at standard conditions

The "Black-oil" approach using pre-defined saturation tables is a three-step process. First the molar fraction of CO_2 dissolved in brine was defined as a function of pressure based on curves generated for the temperature of each individual injection zone respectively (Spycher & Preuss, 2005). After defining the molar fraction, the Rs computation was completed using the methods described from Hassanzadeh et al., 2008. Finally, the Rs values were adjusted to the salinity inputs for each injection zone, using the correlation of Rs to salinity provided by Chang et al., 1998. [redacted]

3.5 CONSTITUTIVE RELATIONSHIPS

Relative permeability behavior and capillary trapping characteristics of both the confining zone and impermeable boundary are recognized as highly impactful to the ability to inject and immobilize supercritical CO_2 within the storage complex. The forces that govern fluid flow in porous media are viscous forces, effects of gravity and capillary imbibition. Fluid flow models are based on the law of conservation of mass, described by Darcy's law.

The rate of displacement of the brine by the CO_2 as well as the extent of the plume require dynamic reservoir modelling based on the initial static model. Hydraulic and structural trapping mechanisms of CO_2 sequestration apply under two phase flow displacement. In porous media containing two phases, one of the two phases will have a tendency to contact a wider surface area of the grain compared to the other phase. The parameter that measures this tendency is defined as wettability; the phases are classified as wetting or non-wetting. The brine is the wetting phase in a CO_2 – brine system. The wetting phase is able to access the smallest pores, while the non-wetting phase is limited to the largest connected pore space. Continuous fluid percolation through pores results in flow of the individual phase. The non-wetting phase in this model, the CO_2, may become disaggregated into separate isolated volumes. The relative permeability of each phase is the ratio of the phase's effective permeability to the absolute permeability and depends on the complexity of the pore system, absolute permeability, wettability, and interfacial tension between the two fluids.

Capillary forces in a subsurface reservoir are the result of multiple factors, including surface and interfacial tensions of both the rocks themselves and the fluids contained within the pore system. The pore network, both in geometry and pore throat size, is a second critical component. Finally, the capillary pressure of a system is the difference in pressure between the two phases. The ability of one fluid to displace another within porous rock, can either be hindered or aided by capillary pressure (Ahmed, 2010). Higher capillary pressures reduce gravity segregation in the subsurface, resulting in a more homogeneous CO_2 saturation plume, in turn increasing the efficiency of CO_2 dissolution. Additionally, higher formation brine salinity reduces the solubility of CO_2 under constant injection pressure (Alkan et al, 2010).

No site-specific core or formation fluid are available for the Project Blue site, therefore analogue capillary pressure curves were obtained from literature to populate the dynamic model. The threshold entry capillary pressures for CO_2 in brine saturated rock were assumed at 1.29 psi for the sand facies and 20 psi for the shale facies. The capillary curves utilized were sourced from the 2010 paper by H. Alkan, Y. Cinar, and B. Ulker, "*Impact of Capillary Pressure, Salinity, and In-situ condition on CO_2 injection into saline aquifers*". The well evaluation program for the injection well will include testing for relative permeability and capillary pressures. Details on the data acquisition plan for the site are contained in the "*Pre-Operational Testing Plan*" submitted in **Module D**.

Darcy's law incorporating multiphase flow is used to forward model individual phase flow, with capillary pressures and relative permeability being the key parameters to introduce the two fluids in the system:

$$q_i = -\frac{k * k_{ri}(S_i) * A}{\mu_i} \frac{dP}{dx}; i = (w, nw)$$

Where:

k	absolute permeability
k_i	relative permeability to phase
S_i	volume fraction of fluid in pore (saturation)
q	flux of the phase (m^3/s)
μ	viscosity of the phase
A	area cross section
dP/dx	pressure gradient over the interval

Indices *w* and *nw* refer to wetting and non-wetting phases.

With the absence of site-specific data, a power law relationship, is assumed between the relative permeabilities and saturation. **Table 17** summarizes the relative permeability and capillary pressure inputs that were used for the dynamic reservoir model and are presented in **Figures 21 and 22.**

The power law equations used to define the relative permeabilities and capillary pressures are defined below:

$$K_{ro} = K_{roep}\left\{\frac{1 - S_w - S_{or}}{1 - S_{wc} - S_{or}}\right\}^{N_o}$$

$$K_{rw} = K_{rwep}\left\{\frac{S_w - S_{wc}}{1 - S_{wc} - S_{or}}\right\}^{N_w}$$

Where:

K_{ro} – Relative permeability of the non-wetting phase

K_{roep} – non-wetting phase end point

S_w – system water saturation

S_{wc} – irreducible water saturation

Sor – residual oil saturation

N_o – non-wetting phase shape factor

K_{rw} – relative permeability of the wetting phase

K_{rwep} – wetting phase end point

N_w – wetting phase shape factor

Table 17: Relative Permeabilities and Saturation Factor inputs into the dynamic model

Phase	Critical Fluid Saturation	Maximum Relative permeability endpoint	Power law saturation exponent
Sand Layers			
Brine	S_{wc}= 0.25	0.8	2.0
Gas	G_{cs}=0.05	0.7	2.7
Shale Layers			
Brine	S_{wc}= 0.40	0.8	2.0
Gas	G_{cs}=0.05	0.7	2.7

3.6 BOUNDARY CONDITIONS

The boundary conditions were established based on the assumption (founded upon regional and local geology) that the target injection reservoirs are continuous throughout the region and that the overlying and underlying confining layers are impermeable to flow and non-transmissive to effluent or pressure.

Outside of geologic conditions the boundary conditions applied to the model allow for the consideration of dissolution and include large pore volume multipliers (**Table 18)** applied to the outermost ring of grid cells to approximate an infinite acting aquifer boundary condition for each injection zone.

Table 18: Pore volume multipliers for boundary conditions applied in dynamic model

Injection Zone	Pore Volume Multiplier
Lower Hosston	50
Cotton Valley *(all Intervals)*	50

The model assumed an open interface in the injection intervals with the surrounding aquifer. Thus, fluids can move, and pressure can transmit freely across the interface.

3.7 INITIAL/STATIC CONDITIONS

Initial conditions for the model and each Injection Zone are given in **Tables 19, 20, 21, and 22**. Initial conditions are based upon offset well data, regional data, and literature sources relevant to the injection formations.

The temperature gradient, and its uncertainty range, was derived from offset well data within the AoR for the Project Blue site. A gradient of 1.66° F/100 ft was derived using a mean annual surface temperature in Union County of 65.5 °F.

Salinity was provided using site specific data from offset wells and compared with the general theory (Archie equation (Schlumberger, 1988)) for determining water quality in clean water-bearing zones from formation water resistivity (R_w). Resistivities of saline solutions vary as a function of NaCl concentration and temperature. The relationship between temperature, NaCl concentration, and resistivity are typically determined by using the Schlumberger Gen 9 Nomograph (Schlumberger, 1997).

Formation pressures were determined by evaluating mud weights from offset drilling reports in Union County. Using the estimated formation pressures, temperatures, and salinities, the initial fluid density was also estimated.

Reservoir conditions observed from the data acquisition on the Project Blue Injection Well will be used to characterize and refine the initial conditions for the project area.

Table 19: Initial conditions – Lower Hosston Injection Zone

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	134	F	3,890	Offset Well Data
Formation pressure	1,742	psia	4,024	0.433 psi/ft per offset class 1 data
Fluid density	1.260	SG	--	Conservative Value to match Pressure gradient
Salinity	170,057	ppm	--	Offset Well Data

Table 20: Initial conditions – Cotton Valley (CV3) Injection Zone

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	144	F	5,000	Offset Well Data
Formation pressure	2,217	psia	5,121	0.433 psi/ft per offset class 1 data
Fluid density	1.557	SG	--	Conservative Value to match Pressure gradient
Salinity	209,004	ppm	--	Offset Well Data

Table 21: Initial conditions – Cotton Valley (CV2) Injection Zone

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	144	F	5,000	Offset Well Data
Formation pressure	2,430	psia	5,614	0.433 psi/ft per offset class 1 data
Fluid density	1.557	SG	--	Conservative Value to match Pressure gradient
Salinity	209,004	ppm	--	Offset Well Data

Table 22: Initial conditions – Cotton Valley (CV1) Injection Zone

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	144	F	5,000	Offset Well Data
Formation pressure	2,603	psia	6,012	0.433 psi/ft per offset class 1 data
Fluid density	1.557	SG	--	Conservative Value to match Pressure gradient
Salinity	209,004	ppm	--	Offset Well Data

Details on the estimated and derived initial conditions are presented in "*Section 2.0 – Site Characterization*" of the Project Narrative, submitted in **Module A.** Formation temperature, pressures, and salinity are expected to increase with depth. No significant lateral spatial disparity is assumed in the salinity or density of the formation fluids. Initial conditions will be updated with data acquired during the drilling of the Injection Well (See "*Pre-Operational Testing Plan*" in **Module D**). The additional core data and logs will provide baseline measurement and be used to update the model.

3.8 OPERATIONAL INFORMATION

Details on the injection operation are presented in **Tables 23, 24, 25, and 26**. These are the specific values used in the model based upon the initial designed program and expectations. Note: as this project evolves, the operational input information will be refined based upon actual site-specific data, the as-built well construction, and permitted injection operations.

<u>Lower Hosston Injection Zone</u>

The base case injection rate is 1,369 ton/d for the Project Blue Injection Well. This equates to a total of 500,000 tons/yr for the Lower Hosston Injection Zone. The target duration of injection is 5 years, and thus, the total amount of CO_2 to be injected into the Lower Hosston is 2.5 MMton.

Table 23: Operating Details – Lower Hosston Injection Zone

Operating Information	Project Blue Injection Well
Location (global coordinates) X Y	1788569.024 217408.996
Model coordinates (ft) X Y	1749200 183250
No. of perforated intervals	1
Perforated interval (ft MSL) Z top Z bottom	4030 4322
Wellbore diameter (in.)	7.5
Planned injection period Start End	2040 2045
Injection duration (years)	5
Injection rate (t/day)	1,369

Cotton Valley Injection Zone – Interval CV3

The base case injection rate is 1,369 ton/d for the Project Blue Injection Well. This equates to a total of 500,000 tons/yr for the CV3 Injection Interval in the Cotton Valley. The target duration of injection is 5 years, and thus, the total amount of CO_2 to be injected into this interval is 2.5 MMton.

Table 24: Operating Details – Cotton Valley – CV3 Injection Interval

Operating Information	Project Blue Injection Well
Location (global coordinates) X Y	1788569.024 217408.996
Model coordinates (ft) X Y	1749200 183250
No. of perforated intervals	1
Perforated interval (ft MSL) Z top	4853 5399

Operating Information	Project Blue Injection Well
Z bottom	
Wellbore diameter (in.)	7.5
Planned injection period Start End	2035 2040
Injection duration (years)	5
Injection rate (t/day)	1,369

Cotton Valley Injection Zone – Interval CV2

The base case injection rate is 1,369 ton/d for the Project Blue Injection Well. This equates to a total of 500,000 tons/yr for the CV2 Injection Interval in the Cotton Valley. The target duration of injection is 5 years, and thus, the total amount of CO_2 to be injected into this interval is 2.5 MMton.

Table 25: Operating Details – Cotton Valley – CV2 Injection Interval

Operating Information	Project Blue Injection Well
Location (global coordinates) X Y	1788569.024 217408.996
Model coordinates (ft) X Y	1749200 183250
No. of perforated intervals	1
Perforated interval (ft MSL) Z top Z bottom	5400 5839
Wellbore diameter (in.)	7.5
Planned injection period Start End	2030 2035
Injection duration (years)	5
Injection rate (t/day) *	1,369

Cotton Valley Injection Zone – Interval CV1

The base case injection rate is 1,369 ton/d for the Project Blue Injection Well. This equates to a total of 500,000 tons/yr for the CV1 Injection Interval in the Cotton Valley. The target duration of injection is 5 years, and thus, the total amount of CO_2 to be injected into this interval is 2.5 MMton.

Table 26: Operating Details – Cotton Valley – CV1 Injection Interval

Operating Information	Project Blue Injection Well
Location (global coordinates) X Y	 1788569.024 217408.996
Model coordinates (ft) X Y	 1749200 183250
No. of perforated intervals	1
Perforated interval (ft MSL) Z top Z bottom	 5841 6200
Wellbore diameter (in.)	7.5
Planned injection period Start End	 2025 2030
Injection duration (years)	5
Injection rate (t/day) *	1,369

Over each 5-year period a total of 2.5 million metric tons of CO_2 is injected per subzone (0.5 MMt/yr). Total time of simulation modeled for the project is 20-years (5-years per zone). The injection period in any single subzone can be extended beyond 5 years until a total injected volume of CO_2 is reached of 2.5 million metric tons, without the combined injection period in all 4 intervals exceeding the project duration of 20 years.

3.9 FRACTURE PRESSURE AND GRADIENT

No site-specific data is currently available for the fracture gradient. However, the fracture gradient for the Project Blue site was estimated using Eaton's Method (Eaton, 1969) and the methodology presented in Moore (1974).

$$FG = \frac{(P_{ob} - P_r)e}{(1 - e)} + P_r$$

Where:

FG = Fracture Gradient

P_{ob} = Overburden Gradient (Figure 11-11 in Moore, 1974) - depth dependent

P_r = Reservoir Pressure Gradient (original)

e = Poisson's Ratio (Figure 11-12 in Moore, 1974) – depth dependent

The nomographs presented in Moore (1974) are solved for all injection intervals at the Project Blue site using the top of the formations projected at location of the Injection Well.

A fracture gradient was then obtained for each of the remaining injection zones using the estimated top of formation as presented in **Tables 27, 28, 29, and 30**.

Table 27: Injection Pressure Details – Lower Hosston Injection Zone

Injection Pressure Details	Project Blue Injection Well
Fracture gradient (psi/ft)	0.726
Maximum injection pressure (90% of fracture pressure) (psi)	2,634
Elevation corresponding to maximum injection pressure (ft MSL)	4,322
Elevation at the top of the perforated interval (ft MSL)	4,030
Calculated maximum injection pressure at the top of the perforated interval (psi)	1,809

Table 28: Injection Pressure Details – Cotton Valley – CV3 Injection Interval

Injection Pressure Details	Project Blue Injection Well
Fracture gradient (psi/ft)	0.753
Maximum injection pressure (90% of fracture pressure) (psi)	3,288
Elevation corresponding to maximum injection pressure (ft MSL)	5,314
Elevation at the top of the perforated interval (ft MSL)	4,853
Calculated maximum injection pressure at the top of the perforated interval (psi)	2,670

Table 29: Injection Pressure Details – Cotton Valley – CV2 Injection Interval

Injection Pressure Details	Project Blue Injection Well
Fracture gradient (psi/ft)	0.769
Maximum injection pressure (90% of fracture pressure) (psi)	3,737
Elevation corresponding to maximum injection pressure (ft MSL)	5,713
Elevation at the top of the perforated interval (ft MSL)	5,400
Calculated maximum injection pressure at the top of the perforated interval (psi)	3,095

Table 30: Injection Pressure Details – Cotton Valley – CV1 Injection Interval

Injection Pressure Details	Project Blue Injection Well
Fracture gradient (psi/ft)	0.769
Maximum injection pressure (90% of fracture pressure) (psi)	4,042
Elevation corresponding to maximum injection pressure (ft MSL)	6,112
Elevation at the top of the perforated interval (ft MSL)	5,841
Calculated maximum injection pressure at the top of the perforated interval (psi)	3,620

The dynamic models for all four injection intervals were run with a bottomhole injection pressure constraint equal to 90% of the conservatively estimated fracture pressure. This restriction impacted the injection rates for the CV1 and CV2 Injection Intervals. Injection rates below 26 mmscfd were modeled for the CV1 for 35 months of injection and for the CV2 for 6 months of injection. The estimated top of the expected perforations is unknown and variable, especially in the Cotton Valley Formation. The depths of the perforations will be dependent on the open hole logging analysis after the Injection Well is drilled.

Site-specific testing for formation pressures in the subsurface will be undertaken during construction of the Project Blue Injection Well. Mini-frac tests on wireline or step rate tests performed after well construction, along with the results of other logs and core tests, will be used to verify that information provided in the permit application related to the fracture pressure of the injection and confining zones is correct. If the calculated fracture pressures of the injection and/or confining zones differ from the assumptions on which injection rates and pressures in this Class VI permit are based, permit conditions will be revised accordingly. Additionally, if there is/are any uncertainty or inconsistencies in calculated fracture pressures within the injection or confining zones, the maximum injection pressure limit may need to be reevaluated based on these data and may be revised to less than 90 percent of the fracture pressure of the injection zone.

3.10 CHARACTERISTICS OF THE CO_2 STREAM

3.10.1 Density and Compressibility

All modeling presented in this submittal assumes 100% CO_2. As mentioned previously, the dynamic simulation Eclipse 100 is run with the “Black-oil” methodology. Therefore, CO_2 properties are input as tables for formation volume factor (FVF) and viscosity as a function of pressure. For the Project Blue site, these tables were generated using Petroleum Experts fluid module of MBAL software using the Peng-Robinson (1978) EOS and the Lohrenz-Bray-Clark correlation for viscosity. Density and compressibility are computed internally by Eclipse 100 simulator based on the FVF versus pressure table and standard density conditions for CO_2 (0.1167 lb/ft^3).

The Peng-Robinson EOS is used throughout the petroleum and chemical industries to model the phase behavior and molar volume (density) of single and multi-component systems with CO_2 as a significant component. CO_2 behaves as a supercritical fluid above the critical pressure and critical temperature listed in **Table 31** below.

Table 31: Critical Property Inputs for CO_2

Parameter	Input Unit
Critical temperature (Tc)	87.761 ºF
Critical pressure (Pc)	1,070.0 psia

The CO_2 properties were generated by the Petroleum Experts MBAL fluid module, using the Peng-Robinson EOS for density calculation and Lohrenz-Bray Clark correlation for viscosity, with the assumption of pure CO_2. This should be standard and should not depend much on software: Tc = 87.761 °F and Pc = 1070 psia (according to NIST REFPROP database: National Institute of Standards and Technology - Reference fluid Properties).

CO_2 density increases as pressure increases and decreases as temperature increases. Because of this relationship, the density of the CO_2 in each of the injection zones is similar. The density of the plume, especially at the leading edge, is of interest. The density contrast between the CO_2 and *in-situ* saline formation water, along with the formation dip, influences the lateral extent and rate of potential plume migration.

The injected CO_2 at the Project Blue site is expected to be soluble in water, which can provide a significant trapping mechanism. This feature affects the reservoir by causing the higher density brine to sink within the formation, thereby trapping the CO_2-enriched brine. This dissolution allows for an increased storage capacity and reduced extent of lateral fluid migration.

3.10.2 Viscosity

CO_2 viscosity is estimated using an implementation of the Lohrenz-Bray Clark method within the dynamic model. The graphs in **Figures 23 and 24** estimated super-critical CO_2 viscosity at nominal pressure and temperatures for each of the injection zones. The values estimated within the Eclipse software are then compared to values estimated using the NIST webbook, which implements the method of (Laesecke and Muzny 2017) to estimate viscosity.

3.10.3 CO_2 and Formation Interactions

It is known that CO_2 and water will form Carbonic Acid (H_2CO_3) which in turn has the capability to dissolve calcium in the formation. This can alter formation permeability and porosity depending on the native mineralogy.

This study does not consider CO_2 reactions with the formation matrix. Future modeling will consider these aspects given the results of core and petrophysical analysis obtained from the Project Blue Injection Well.

3.10.4 Solubility

The injected CO_2 at the Project Blue site is expected to be soluble in water, which can provide a significant CO_2 trapping mechanism. This feature affects the reservoir by causing the higher density brine to sink within the formation thereby trapping the CO_2-entrained brine. This dissolution allows for an increased storage capacity and decreased fluid migration.

The Eclipse 100 model includes CO_2 solubility in brine, through the "Black-Oil" fluid modeling approach discussed above in *section 3.5.3 Dissolution of CO_2 in Brine*

4.0 COMPUTATIONAL MODELING RESULTS

4.1 PREDICTIONS OF MODEL BEHAVIOR

The model considers advective transport and dissolution of injected CO_2 into each of the injection zones and subzones: Lower Hosston and CV3, CV2, and CV1 respectively. Each of the zones (Lower Hosston and Cotton Valley) have been modeled separately as they are assumed separated by regionally extensive stratigraphic units which have demonstrated that the injection zones are not hydraulically connected and therefore the model confines flow within the modeled injection units/intervals.

Model results such as plume extent and pressure build-up are dependent on the geologic conditions assigned to the model (structure, thickness, porosity, permeability), and fluid properties (viscosity, density). In addition, the injection rate (volume & mass) will impact the pressure build-up at the well and in the surrounding reservoir. The volume (rate and duration) impacts the ultimate plume extent.

This permit pertains to one proposed Injection Well which will inject incrementally into each injection interval for 5-year timeframes: respectively **Table 32**. The maximum injection rate into the well has either been limited by the plume extent, well design or maximum allowable fracture initiation pressure. In all cases, skin is assumed to be zero and the well fully penetrates the formation.

Table 32: Injection schedule for dynamic modeling of CO_2 injection at 26mmscf/day or 500,000 metric tons per year into the Project Blue CCS Site. Grey filled cells represent injection and Orange filled cells represent observation

	Active Injection Period (Year End)				Post Injection Period (Year End)				
	2030	**2035**	**2040**	**2045**	**2055**	**2065**	**2075**	**2085**	**2095**
L. Hosston									
CV 3									
CV 2									
CV 1									

4.2 MODEL CALIBRATION AND VALIDATION

Currently, site specific data is not available for model calibration or a detailed sensitivity analysis. The initial model will be updated with site specific data acquired during the drilling of the Injection Well. Initial conditions and input parameters will be adjusted to reflect the data from site specific core and logs. The model will then be calibrated against history matching once injection operations commence. A model calibration will be performed prior to all AoR reevaluations.

The parameters used in the initial model iteration are established in lieu of site-specific data and reflect a conservative scenario based on the information and data currently available. Changes in the *in-situ* water density, composition, distribution of flow units, net thickness, properties such as porosity, permeability, and rock compressibility may yield changes in final pressure and plume growth rate and lateral extent at the end of the modeled 5-year period for each injection zone and subzone. A sensitivity analysis may be performed with additional model simulations using data acquired from the Injection Well to meet the requirements pursuant to 40 CFR 146.93(c)(2)(iv), should Lapis Energy request an Alternative PISC observation timeframe at a future date.

5.0 MODEL RESULTS

5.1 PREDICTED POSITION OF THE CO2 PLUME

The approximate plume radius (saturation) for each modeled zone, is presented in **Appendix 7.** The time-periods reflect a total of 20 years of injection, with shut-in (post-closure) period of 50-years from end of injection into the Lower Hosston; total time series is 70-years. Note that each zone is modeled for injection of 5-years each. The 50-year PISC observation is based upon the injection operations ceasing in the Lower Hosston Injection Zone (year-end 2045)

- Figure 7.1 in Appendix 7 – Lower Hosston Injection Zone
- Figure 7.2 in Appendix 7 – Cotton Valley Injection Zone – CV3 Injection Interval
- Figure 7.3 in Appendix 7 – Cotton Valley Injection Zone – CV2 Injection Interval
- Figure 7.4 in Appendix 7 – Cotton Valley Injection Zone – CV1 Injection Interval

For each modeled injection zone, the CO_2 plume is presented in time increments all on one figure per zone to track growth. The plume radiates outward from the point of injection for all intervals. Since information available to characterize the subsurface does not indicate the presence of sealing faults or stratigraphic barriers near the Project Blue site, and the structural dip is only slight, the CO_2 plume extends nearly radially from the injection site, but trends slightly northeast due to dip.

Due to the stratigraphic architecture differences in each of the injection intervals the vertical and radial migration characteristics vary slightly.

The Lower Hosston contains the largest plume extent at both end of injection and end of observation (most likely a result of the higher overall permeability). Migration is radial around the well bore during injection with a slight bias to the north. During the observation period, migration continues to the north (~2,543 ft) and east (~3,747 ft). There is little to no additional migration to the south or west of the plume.

Each of the Cotton Valley plumes are very similar in overall size at the end of their respective injection period, with minor differences in the orientation and grid cells of maximum plume extent. This is most likely a result of variations in stratigraphic architecture and facies prediction in terms of reservoir as well as rock properties (porosity and permeability). However, the overall migration is radial from the wellbore for the CV3, CV2, and CV1 Injection Intervals.

At the end of observation, the CV3 Injection Interval is the smallest of the plumes. The CV2 has the largest overall plume and the CV1 shows the most migration to the west of the facility, but not in any other direction. The CV2 shows migration in a continued radial manner with a very slight bias to the north and east.

5.1.1 Maximum Plume Extent

Analytical models from Celia and Nordbotten (2009) and Yamamotoa and Doughty (2011) suggest that within a *vertically* contiguous injection layer the plume is smallest at the base and extends asymptotically outward with the maximum extent at the boundary of the confining layer. The analytical approach can mathematically extrapolate the saturation profile to the near molecular level. The analytical model, however, is limited to simplifying assumptions regarding spatial distribution of properties.

The numerical model determines pressure and saturation in each grid block, with each grid block having its own volume and potentially unique properties (permeability, porosity). Additional layers with finer resolution in the numerical model can show the absolute extent of the plume to be greater than presented with fewer coarser layers, depending on properties assigned to the grid (Yamamotoa and Doughty, 2011). Finer layering has been utilized at the top of the sector models to account for this model resolution effect.

All layers incorporate spatial variability of sand and shale facies, porosity, and permeability. A base-case kv / kh ratio of 1 has been assumed in all layers, until site specific data has been collected.

The plume extents reach their maximum at the end of the PISC timeframe for all reservoirs. The maximum extent of the plumes is shown in **Figures 7.1, 7.2, 7.3, and 7.4 (year-end 2095) in Appendix 7.** Note that the 50-year observation time commenced with the cessation of injection operations in the Lower Hosston. By this time, the CV1 has been shut-in for 15 years, for a total observed PISC timeframe of 65 years.

5.1.2 Plume Migration Post-Closure

Post shut-in plume migration is primarily to the northeast of the injection wells due to minor regional dip and density contrast. There is essentially no migration to the south, and minimal to the east and west of the injection wells. This is due to the structural dip, and the lack of hydraulic barriers that mitigate plume migration in the model.

It is expected that the inclusion of capillary trapping and imbibition in the model in future model iterations and using site specific data will show the plume stabilization. These features will be included using information provided by the Injection Well.

5.2 PREDICTED POSITION OF THE PRESSURE FRONT

Appendix 8 shows the estimated pressure contours in the top layer of each injection zone starting with the initial pressure and at 5-year increments during injection operations. These pressure fields are the result of injection into the injection zones and subzones for 5-year periods of operation.

- **Figure 8.1 in Appendix 8** – Lower Hosston Injection Zone
- **Figure 8.2 in Appendix 8** – Cotton Valley Injection Zone – CV3 Injection Interval
- **Figure 8.3 in Appendix 8** – Cotton Valley Injection Zone – CV2 Injection Interval
- **Figure 8.4 in Appendix 8** – Cotton Valley Injection Zone – CV1 Injection Interval

Injection commences first in the deepest interval (CV1) for 5-years, then moves upwards into the CV2 interval for 5-years, then the CV3 interval for 5-years, and finally the Lower Hosston for 5 -years **Table 32.** All intervals are independently modeled, and injection never occurs in two zones simultaneously. As a result of this operational strategy, the figures presented in **Appendix 8** present the maximum pressure build up at end of injection for each zone. Discussion on the pressure decay at the cessation of injection operations is contained in the *"E.3 – Post Injection Site Closure and Site Care Plan"* contained in **Module E.**

The pressure is the highest at the injection point and tapers off away with distance around the Injection Well for all zones. The predicted pressure profiles will be compared to observed plume and pressure data in the field and will be used to fulfil the EPA requirement to reevaluate the AoR at 5-year intervals during injection and for the PISC timeframe.

6.0 AREA OF REVIEW

Under the 40 CFR 146.84 regulations, the AoR is the area within which the owner or operator of a Class VI injection well must identify all artificial penetrations (APs) that penetrate the confining zone and/or injection zone and determine whether they have been completed or plugged, so that they do not provide conduits for fluid movement. Artificial penetrations constitute a possible threat to human health or the environment because of their potential for conveying material out of the injection zone (no migration standard) and/or into a USDW (non-endangerment standard).

AoR delineation has been determined for the Lapis Energy Project Blue site using geological characterization data and computational modeling data showing the projected lateral and vertical migration of the CO_2 plumes (for each interval). This includes an understanding of the projected critical pressure fronts, and the pressure front decay and plume stabilization at post closure.

6.1 CRITICAL PRESSURE CALCULATIONS

The Cone of Influence (COI) is the area that surrounds the well where increased pressures due to injection operations can be sufficient to initiate vertical migration of fluids out of the injection zone through a potential conduit. The COI is determined for each injection zone and interval based upon the shallowest expected geologic depth to top of formation. This methodology used for calculating the cone of influence was developed by E. I. du Pont de Nemours & Co. (DuPont), and it is also generally consistent with previous methods (Barker, 1981; Clark et al., 1987; Collins, 1986; Davis, 1986; Johnson and Greene, 1979; Johnson and Knape, 1986; Warner, 1988; Warner and Syed, 1986).

The basic underlying assumption in this approach is that in the absence of naturally occurring, vertically transmissive conduits (faults and fractures) between the injection interval and any USDW, the only potential pathway between the injection zone and any USDW is through an artificial penetration (active or inactive oil and gas well(s)). In order to pose a potential threat to a USDW (*i.e.*, pressure buildup from injection sufficient to drive fluids into a USDW), the pressure increase in the injection interval would have to be greater than the pressure necessary to displace the material residing within the borehole. This pressure necessary to displace the material residing within the borehole is defined as the allowable buildup pressure. Therefore, the cone of influence is the area within which injection interval pressures are greater than the allowable buildup pressure.

6.2 AOR DELINEATIONS

The predicted AoR (CO_2 plume and pressure front) are delineated based upon the reservoir modeling results using anticipated injection operation parameters [per 40 CFR 146.84(c)(1)(i)]. The pressure front, which proceeds the plume front, is delineated by using COI methodology and allowable pressure build-up in a borehole, which has been verified and used in multiple Class I applications in the Gulf Coast to evaluate the pressure fronts for at least 30 years. The pressure front will be the expected maximum extent of the AoR, and therefore is used in the final AoR delineation. The COI is the area within each injection interval, where pressures are greater than the allowable buildup pressure.

A static mud column exerts pressure. For an abandoned well to provide a pathway for fluid movement, the pressures acting on the static mud column (pressure due to injection plus original formation pressure) must be greater than the static mud column pressure. In a static fluid column, the gel strength of the mud must also be considered.

In this case, for upward fluid movement to begin, original formation pressure (P_f) plus the pressure due to injection (P_i) must be greater than the static fluid column pressure plus the gel strength of the mud. This relationship is based on a simple balance of forces (Davis, 1986):

$$P_f + P_i > P_s + P_g$$

Where:

P_f = original formation pressure (psig)

P_i = formation pressure increases due to injection (psi)

P_s = static fluid column pressure (psig)

P_g = gel strength pressure (psi)

Therefore, pressure increase due to injection must be greater than static fluid column pressure minus original formation pressure:

$$P_i > P_s + P_g - P_f$$

These relationships are used to determine the AOR and Cone of Influence for each of the injection intervals taking into consideration the dipping plane and redistribution of fluids within the reservoir during CO_2 injection. This study uses the predicted model pressure ($P_i + P_f$) at the end of the 5-year injection period, for each grid cell, in the top layer, minus the hydrostatic head (P_s) due to a 9.3-lb/gal column of "mud" at the same grid location to determine the AoR and COI. The 9.3-lb/gal was chosen as it is the lowest mud weight documented in the injection zones within the surrounding area of the site.

The COI is the area where the pressure build-up due to injection is greater than the hydrostatic head of the mud column $(P_i + P_f) – Ps > 0$ (**Figure 25**). The AoR is defined as the point where the hydrostatic head pressure equals the pressure exerted by the column of mud (neglecting gel strength), $(P_i + P_f) – Ps = 0$.

The critical pressure was calculated for the top of each formation using the hydrostatic head and gel strength. The COI and AoR are illustrated for each of the injection intervals at the Project Blue site. **Figures 9.1, 9.2, 9.3 and 9.4** in **Appendix 9** provide detailed plots showing the AoR and COI for each injection interval with a 1-mile buffer.

7.0 CORRECTIVE ACTION PLAN

The potential for vertical movement of CO_2 through man-made conduits in the form of unabandoned, improperly abandoned, or active wells is addressed in this section. This corrective action evaluation concludes that there will be no migration of CO_2 and/or formation brine into a USDW.

Whenever an effluent is injected into a subsurface geologic formation, the pressure within the injection sand(s) will increase. This pressure increase will be greatest at the injection well(s) and will decrease with distance away from the injection site. Because of the driving force supplied by the increase in formation pressure within the injection sand, artificial penetrations (legacy wells) within the radius of the CO_2 plume have the potential to convey CO_2 out of the injection zone, and even into a USDW. In an unplugged borehole, this driving force is opposed by the flow resistance of the material (swelled clay, creeped shale, borehole collapsed material, in situ drilling mud) residing in the borehole. Vertical fluid movement out of the storage complex cannot begin until the pressure in the injection zone has increased beyond the critical threshold value necessary to overcome the flow resistance of the borehole material. If the pressure buildup in the injection sand is less than the threshold value, the artificial penetration cannot serve as a conduit for flow of formation brines out of the injection zone. Therefore, if the CO_2 plume does not reach the artificial penetration, or the critical pressure for brine crossflow is not exceeded for a legacy well bore within the AoR, they have been evaluated as safe, and corrective action to plug the well is not necessary.

After injection operations are completed, either temporarily or permanently, the pressure buildup within the injection sand will decrease to a value approaching the original formation pressure. This occurs rapidly, within a few years of cessation of injection. Upon pressure stabilization in the injection sand, the CO_2 plume will be in hydrostatic equilibrium with surrounding formation brines. Consequently, no driving force capable of conveying CO_2 or formation brines out of the injection zone will be present.

An Artificial Penetration Protocol is used to identify, locate, and evaluate artificial penetrations within the delineated AoR. A methodology for evaluating the construction or plugging of wells within the AoR was developed to evaluate a well's potential to act as a vertical conduit. Wells that are known to have been plugged across the injection interval, obviously cannot provide pathways for migration from the injection zone or injection-induced movement of fluids into a USDW, and do not require detailed evaluation. Wells that are plugged across the lowermost USDW, or at some point between the injection interval and the lowermost USDW, cannot serve as pathways for injection-induced movement of fluids into a USDW, but are evaluated as potential pathways for migration from the injection zone. Wells not known to have been plugged in either manner are further evaluated to determine whether they can serve as potential pathways for migration from the injection zone or for injection-induced movement of fluids into a USDW.

7.1 TABULATION OF WELLS WITHIN THE AOR

A thorough record search was conducted during preparation of this Class VI permit application for the Lapis Energy Project Blue site to locate and evaluate all wells that lie within the designated AoR. Prior to delineating the AoR, Lapis Energy compiled well locations and records for all wells within a 5-mile radius from the proposed injection site to cover a larger Area of Interest (AoI). From the records obtained for each well, a determination of penetration of the confining and injection zones was made. This first step was a “due diligence” approach to identify issues at early stages of project conceptualization.

Once the final AoR was delineated, a tabulation of 45 wells (**Table 33**) was compiled to represent the potentially effected wells located in the AoR (**Figure 26)** [per 40 CFR 146.82(a)(4)]. Supporting documentation (well records/scout tickets) for each well is presented in **Appendix 10.** Please Note: AP No. 1 will be re-entered and completed across the injection zones to serve as the north In-zone (IZ) Monitoring well.

Table 33: Tabulation of Artificial Penetrations within the delineated AoR

Artificial Penetration Number	Operator	Lease & Well Number	Well Spud Date	Status	Date Plugged	Well Depth (feet)	P&A Mud Wt. (ppg)	Log Mud Wt. (ppg)	Ground Level Elevation (feet)	Depth Top Injection Zone (feet-TVDSS)	Depth Cement Plugs (feet)	Surface Casing Size (inch)	Surface Casing Depth (feet)	Protection Casing Size (inch)	Protection Casing Depth (feet)	Casing Cutoff (feet)	Open Hole Size (inch)	Penetrates Confining Zone Interval	Penetrates the Injection Zone	Contained within the Plume	Passes Pressure Evaluation for Non Endnagerment and vertical migration
1	Schuler Drilling Company, Inc.	EDC No. 1	8/17/1997	D&A	8/30/1997	6,564	9.6	9.6	192.5	-3,697	Surface 1,591-1,691 6,270-6,370	8 5/8	1,641	--	--	--	7 7/8	Yes	Yes	Yes	Yes
1A	Rovenger Oil Company	W.H. Perdue No. B-3	8/5/1929	D&A	10/12/1929	3,278	No Data	No Log	184.0	NDE	No Records	10	41	6 5/8	3,223	--	--	Yes	No	Yes *NDE	Not Applicable - NDE
1B	Rice	Whately No. 1	1/1/1931	D&A	5/18/1931	2,186	No Data	No Log	190.0	NDE	No Records	10	92	--	--	--	--	No	No	Yes *NDE	Not Applicable - NDE
2	Wilbur Davis Production Company	W. Goodwin No. 1	9/5/1986	P&A	4/30/1992	3,545	10.2	10.2	168.0	NDE	Surface 3,000-3,200	8 5/8	151	4 1/2	3,286	--	7 7/8	Yes	No	No	Not Applicable - NDE
3	Wilbur Davis Production Company	Southern Hotel No. 1	12/18/1987	D&A	12/22/1987	3,565	9.6	9.6	203.0	NDE	Surface 750-850	8 5/8	155	--	--	--	7 7/8	Yes	No	Yes *NDE	Not Applicable - NDE
4	Mann Oil Co. LLC	Calvert No. 1	10/29/1921	D&A	11/29/1921	2,141	No Data	No Log	209.0	NDE	No Records	10	171	6 5/8	2,101	--	--	No	No	No	Not Applicable - NDE
5	L.H. Wentz	S. Flournoy et al. No. 1	12/4/1947	D&A	12/21/1947	4,993	10.2	10.2	157.0	-3,778	Surface 850	8 5/8	245	--	--	--	8 5/8	Yes	Yes	No	Yes
6	Walter Bollenbacher	Haney No. 1	12/18/1963	P&A	12/22/1963	3,502	9.8	9.8	211.0	NDE	No Records	8 5/8	156	--	--	--	7 7/8	Yes	No	No	Not Applicable - NDE
7	Walter Bollenbacher	Haney No. 2	1/2/1964	D&A	4/15/1964	3,005	9.8	9.8	233.0	NDE	No Records	8 5/8	102	--	--	--	7 7/8	Yes	No	Yes* NDE	Not Applicable - NDE
8	F.S. Anderson	J. Burns No. 1	10/15/1923	D&A	Not Reported	2,047	No Data	No Log	142.0	NDE	No Records	10	60	6 4 1/2(liner)	1,962 41 ft (no data)	--	--	No	No	No	Not Applicable - NDE
9	Caddo Oil Co. Inc	J.P. Pickering No. 1	7/20/1953	D&A	1/20/1954	2,153	No Data	No Log	199.0	NDE	No Records	10 3/4	60	6 5/8	2,150	--	--	No	No	No	Not Applicable - NDE
10	Zach Brooks Drilling Co.	J.P. Pickering No. 1	12/20/1950	D&A	1/19/1952	3,400	No Data	No Log	199.0	NDE	No Records	9 5/8	85	5 1/2	2,152	--	--	Yes	No	No	Not Applicable - NDE
11	Ackerley & Buddelson	B. Murphy No. 1	12/2/1926	P&A	Not Reported	2,168	No Data	No Log	179.0	NDE	No Records	No Casing Set	--	--	--	--	--	No	No	No	Not Applicable - NDE
12	Drillers Oil and Development	J.A. Haney No. 1	3/15/1932	P&A	Not Reported	2,300	No Data	No Log	196.0	NDE	No Records	6	2,135	--	--	--	--	No	No	No	Not Applicable - NDE
13	Brown & Byrnes Trustees	J.A. Haney No. 1	1/5/1930	P&A	3/15/1930	2,905	No Data	No Log	203.0	NDE	No Records	10	112	--	--	--	--	No	No	No	Not Applicable - NDE
15	Drillers Oil and Development	J.P. Pickering No. 1	9/17/1931	P&A	3/14/1932	2,165	No Data	No Log	168.0	NDE	1,728-1,928 2,128-2,165	10	90	6 4 1/2 (liner)	2,126 2,121-2,165	--	--	No	No	No	Not Applicable - NDE
18	Schuler Drilling Company, Inc.	Brasher No. 1	9/23/1964	D&A	9/30/1964	4,625	10.3	10.3	199.0	-3,828	0-7 825-850	8 5/8	159	--	--	--	7 7/8	Yes	Yes	No	Yes
23	O'Brien Operting Company Co.	J. Parnell et al. No. 1	10/25/1989	P&A	8/10/2020	5,800 PBTD 6,800	Heavy Mud	9.7	236.0	-3,822	0-30 5,690-5,700	8 5/8	760	5 1/2	5,800	--	7 7/8	Yes	Yes	No	Yes
24	Crude Oil LLC	J. Parnell No. 2	10/8/1990	Suspended	8/10/2020	6,001	Heavy Mud	9.6	253.0	-3,815	0-30 4,490-4,500	8 5/8	762	5 1/2	5,730	--	7 7/8	Yes	Yes	No	Yes
25	Geo J. Rice e al.	Newton No. 1	5/3/1927	D&A	1/20/1928	3,286	No Data	No Log	226.0	-3,810 (est)	No Records	10	102	6	2,919	--	--	Yes	No	No	Not Applicable - NDE
26	Kin-Ark Oil Company	Haney No. 1	2/24/1956	P&A	7/10/1956	6,763	10.8	10.8	232.0	-3,820 (est)	Surface 6,655-6,720	9 5/8	828	5 1/2	6,759	Csg cut at 2,600 ft	8 3/4	Yes	Yes	No	Yes
27	L.H. Wentz	J.A. Haney No. 1	11/19/1947	D&A	11/29/1947	3,971	9.8	9.8	234.0	NDE	Surface 840-860	8 5/8	231	--	--	--	8 5/8	Yes	No	No	Not Applicable - NDE
28	Braddock Exploration, LTD.	McMahan No. 1	12/19/1982	D&A	12/31/1982	6,735	9.7	9.7	190.0	-3,756	Surface 1,000-1,100 6,545-6,645	8 5/8	757	--	--	--	7 7/8	Yes	Yes	No	Yes
29	R.E. Williams	J. Parnell No. 1	8/28/1962	D&A	9/21/1962	6,749	10.1	10.1	237.0	-3,816	No Records	8 5/8	987	--	--	--	7 7/8	Yes	Yes	No	Yes
30	T.L. James and Co - J.C. Wynne	Whatley No. 1	10/27/1971	D&A	11/10/1971	6,699	9.8	9.8	211.0	-3,739	Surface 762-850	8 5/8	812	--	--	--	7 7/8	Yes	Yes	No	Yes
31	South Ranch Oil Company	I.G. Hammond et al. No. 1	12/12/1980	P&A	10/5/1987	7,000	Heavy Mud	9.3	207.0	-3,829	Surface 720-820 1,460 - 1,560 6,595 CIPB	8 5/8	730	5 1/2	6,738	Csg cut at 5,907 ft	7 7/8	Yes	Yes	No	Yes
32	D.J. Johnston, Trustee	Haney No. 1	11/8/1924	D&A	12/14/1924	2,152	No Data	No Log	170.0	NDE	No Records	10	53	6	2,072	--	--	No	No	No	Not Applicable - NDE
40	Sam M. Richardson	J.P. Hammond No. 1	11/28/1933	D&A	1/2/1934	2,207	No Data	No Log	218.0	NDE	No Records	10	60	--	--	--	--	No	No	No	Not Applicable - NDE
42	Hurley Petroleum Corporation	Anderson No. 1	12/30/1985	P&A	1/24/1995	6,740	9.7	9.7	207.0	-3,826	0-30 700-800 1,400-1,500 6,530-6,670	8 5/8	758	5 1/2	6,740	Csg cut at 1,900 ft	7 7/8	Yes	Yes	No	Yes

Table 33: Tabulation of Artificial Penetrations within the delineated AoR

Artificial Penetration Number	Operator	Lease & Well Number	Well Spud Date	Status	Date Plugged	Well Depth (feet)	P&A Mud Wt. (ppg)	Log Mud Wt. (ppg)	Ground Level Elevation (feet)	Depth Top Injection Zone (feet-TVDSS)	Depth Cement Plugs (feet)	Surface Casing Size (inch)	Surface Casing Depth (feet)	Protection Casing Size (inch)	Protection Casing Depth (feet)	Casing Cutoff (feet)	Open Hole Size (inch)	Penetrates Confining Zone Interval	Penetrates the Injection Zone	Contained within the Plume	Passes Pressure Evaluation for Non Endnagerment and vertical migration
43	C.A. Kinard	E.P. Hammonds No. 1	1/15/1946	D&A	2/4/1946	3,696	9.9	9.9	197.0	NDE	None	No Casing Set	--	--	--	--	8 3/4	Yes	No	No	Not Applicable - NDE
52	Hurley Petroleum Corporation	Bush et al. No. 1	1/18/1985	P&A	1/19/1995	6,800	9.5	9.5	210.0	-3,756 (est)	0-30 1,250-1,450 6,510-6,650	9 5/8	1,350	5 1/2	6,766	Csg cut at 4,300	8 3/4	Yes	Yes	No	Yes
98	Transcontinental Oil Co.	Goodwin No. 1	11/1/1921	D&A	12/1/1921	3,001	No Data	No Log	167.0	NDE	No Records	10	204	6 4 1/2 (liner)	2,036 2,166	--	--	No	No	No	Not Applicable - NDE
99	Joe R. May Production	Roper No. 11	8/10/1925	Active	--	2,555	--	No Log	155.0	NDE	--	8 5/8	124	5 1/2	2,204	--	--	No	No	No	Not Applicable - NDE
100	J.D. Reynolds Company	Byrd No. 1	8/16/1961	D&A	8/21/1961	3,368	10.3	10.3	197.3	NDE	Surface 780-829	10 3/4	102	--	--	--	8 3/4	Yes	No	No	Not Applicable - NDE
103	Allen Beadel & W.A. Field	O.B. Murphy No. 1	6/15/1924	P&A	9/19/1924	2,105	No Data	No Log	162.0	NDE	No Records	10	150	6 4 1/2 3 1/2 (liner)	1,700 2,012 1,985 - 2,105	--	--	No	No	No	Not Applicable - NDE
104	Sam S. Alexander	J.P. Pickering No. 1	5/3/1939	P&A	8/14/1939	3,371	9.8	9.8	169.0	NDE	No Records	10	100	--	--	--	9 7/8 8 3/4	Yes	No	No	Not Applicable - NDE
A4	E.L. Chapman	B. Thompson et al. No. 1	Pre 1930	D&A	Pre 1930	2,525	No Data	No Log	150.0	NDE	No Records	--	--	--	--	--	--	No	No	No	Not Applicable - NDE
A6	E. Lucas	P. Newton No. 1	Pre 1930	D&A	Pre 1930	2,236	No Data	No Log	248.0	NDE	No Records	--	--	--	--	--	--	No	No	No	Not Applicable - NDE
A9	Drillers Oil and Development	J.P. Pickering No. 1	9/12/1931	D&A	4/11/1932	2,172	No Data	No Log	171.0	NDE	No Records	4 1/2	2,138	--	--	--	--	No	No	No	Not Applicable - NDE
A11	Alcal Oil Co.	J.A. Haney No. 1	Pre 1930	D&A	Pre 1930	2,770	No Data	No Log	185.0	NDE	No Records	--	--	--	--	--	--	No	No	No	Not Applicable - NDE
A12	Huddleson Ackeoly	Murphy No. 1	7/16/1926	D&A	1/7/1927	2,182	No Data	No Log	194.0	NDE	No Records	10	100	6	2,168	--	--	No	No	No	Not Applicable - NDE
A26	King	C.F. Enis No. 1	Pre 1930	D&A	Pre 1930	2,298	No Data	No Log	235.0	NDE	No Records	--	--	--	--	--	--	No	No	No	Not Applicable - NDE
A33	Quakins Petroleum Co.	B. Montgomery No. 1	Pre 1930	D&A	Pre 1930	2,282	No Data	No Log	196.0	NDE	No Records	--	--	--	--	--	--	No	No	No	Not Applicable - NDE
A40	Sam M. Richardson	J.P. Hammond No. 2	8/21/1934	D&A	9/23/1934	2,168	No Data	No Log	170.0	NDE	No Records	10	56	--	--	--	--	No	No	No	Not Applicable - NDE
A105	Artex Oil Co Inc,	H.A. Goodwin No. 1	Pre 1930	D&A	Pre 1930	2,139	No Data	No Log	171.0	NDE	No Records	--	--	--	--	--	--	No	No	No	Not Applicable - NDE

P&A= Plugged and Abandoned
D&A= Dry and Abandoned
NDE= Not Deep Enough

7.1.1 Data Bases and Search Protocol

The AoR describes the area within which the owner or operator of a Class VI injection well must identify all artificial penetrations. These artificial penetrations could serve as potential conduits that would permit formation brine and or injected fluids to enter USDW and must be mitigated accordingly. This Artificial Penetration Protocol that follows consists of a program for well identification from various data sources, including file search at the Arkansas Oil and Gas Division and online public and commercial services.

7.1.1.1 Data Sources

A specific and consistent methodology was used to identify all artificial penetrations within the AoR surrounding the Project Blue site. Several data sources were utilized to locate pertinent information regarding each artificial penetration. Revised or updated base maps from Tobin Surveys, Inc., Cambe Geological Services, Inc., Arkansas Geological Society, and State of Arkansas were initially used to identify well locations and establish a general background on the wells in the AoR. Databases were searched between May – December 2022 using the online database from the Arkansas Oil and Gas Comission (AOGC) for logs and scout cards. The regional geologic and well log libraries of IHS Energy, TGS, and GeoMap Co., all commercial geologic and well log service companies, were also researched for well logs and scout tickets applicable to each well identified in the AoR.

If discrepancies existed among data sources, the reported state data was considered to be the most accurate. If data were not available, hardcopy searches would be performed to complement the search. The following discussion provides a synopsis of the procedures used to procure this state data.

7.1.1.2 Search Procedure

To begin research of non-freshwater artificial penetrations in the AoR, the search first obtains base maps available from commercial mapping companies. These base maps are used to determine the well locations and land survey grids such as townships, ranges, and sections. A larger AoI was then defined, over potentially affected areas. The larger initial search footprint provides a due diligence of wells that may be near or surrounding the outside perimeter of the finalized AoR.

The AOGC is the state well regulatory authority and repository for records of all wells drilled in the state and is considered the most reliable source of well data in Arkansas. This agency can usually provide 95 to 100 percent of the data needed, along with the online resources.

In instances where complete data are unavailable within the AOGC filing system, the search protocol uses various outside sources, including but not limited to the following:

Arkansas Geological Survey: This agency contains a library of geological reports, which, in some cases, provide information pertaining to a well with missing data. There also may be information relevant to the completion and plugging methods utilized in specific areas and/or during time periods. The Geological Survey can also provide recommendations of little known or underutilized sources of information.

Commercial Log Libraries: When required data cannot be obtained from the AOGC, data can be acquired using membership privileges with a commercial geologic and well log library. These libraries maintain extensive electric log collections as well as scout ticket files. Scout tickets often prove very valuable since full operator name or alternative operator names are listed. These alternative operator names often allow researchers to re-enter the AOGC filing system with previously unknown record leads. The additional log data provide validation of well locations when discrepancies arise. Additionally, details such as drilling fluids for the well and hole size are provided, which may not be included on state forms.

Direct Operator Contact: If researchers are unable to find the desired information within the filing system of the AOGC, or a private log library, then soliciting direct operator contact can be another option to obtain data on key wells, if still active.

From organization reports on file with the AOGC, the operator addresses and telephone numbers can be retrieved, and the operator can be contacted to try and obtain well file copies or research data on the well.

As is often the case, operators of wells with incomplete records are no longer viable business entities and the address and telephone number indicated on the organization report are no longer valid.

In instances where the previous operator cannot be contacted or located, it is possible to obtain the name of the drilling contractor, cementing company, or logging company. These persons and/or companies are sometimes the only contacts available and may be able to provide partial well data on a well or contain historical records.

County Deed Records: In some cases, available base maps may indicate a well was drilled in an area, but the map does not indicate an operator or lease name. It may be necessary to determine the genealogy of the mineral ownership and various lessors on a specific tract of land. By examining deed records on file in the county of interest, one is able to ascertain the names of various individuals and/or companies that once owned mineral or drilling rights to a tract of land. These names can be utilized when re-examining the records on file with the various aforementioned public and private information sources.

Aerial Photography: A review of past and current aerial photographs can assist in determining the existence of wells in an area (if required). Aerial photographs are on file with various public agencies and private firms. Although these photos do not indicate operator or lease names, they can be beneficial in establishing base map errors or in locating a well on the surface.

For the Lapis Project Blue site, the well locations and completion data were acquired using IHS, AOGC, Tobin, TGS, and Cambe resources. Data for all wells within the final definitive AoR were available and additional searches as noted above were not required. Wells were plotted using their reported surface locations and compared to the mapped area of interest surrounding the injection site. Wells that were within 5 miles of the injection well were identified as part of the larger AoI. This resulted in the identification of over 120 wells in the initial evaluation and are identified on all figures in this permit application as artificial penetrations (AP Nos.). However, there are only 45 artificial penetrations within the delineated AoR. Each artificial penetration was then investigated regarding its total depth based on completion reports and well logs.

7.1.2 Well Evaluation

Each permitted artificial penetration (active/abandoned) was evaluated as to the adequacy of construction and plugging to determine the potential of the penetration to convey fluid from an injection zone into the overlying USDWs (non-endangerment) and the potential of the penetration to convey injected effluent out of the injection zone (no migration) [40 CFR 146.84 (c)(3)].

For the purpose of the evaluation, a properly constructed well (producing, injecting, shut-in, temporarily abandoned, *etc.)* is defined as a well in which the surface casing has been set through all USDWs. These wells are constructed to standards for protecting freshwater aquifers. Wells with "short" surface casing that does not extend below all USDWs, may potentially present a conduit outside of the protection and/or production casing, or open hole, into USDWs. These wells are labeled as "potential problem wells" and are further evaluated or modeled for potential upward movement of fluids. Although the drilling fluid in the annulus would provide the same resistance to vertical fluid movement as a mud plug in an open wellbore, wells that were constructed improperly were also listed as potential problem wells and evaluated or modeled for possible vertical fluid movement.

Cement volume calculations were made on each well that has full protection and/or production casing left intact in the well. Only conservative data values were used in the calculations. Additionally, one inch was added to the borehole diameter and all slurry volumes were calculated using Class H cement with 0 percent gel (1.06 ft^3/sack-slurry volume).

7.1.3 Wells Penetrating the Confining Zone

Wells that penetrate the confining and/or injection zone may have the potential for conveying fluid from the injection zone to an overlying formation or from the injection zone to an overlying USDW.

Available geophysical well logs from the artificial penetrations within the AoR were evaluated to determine which of the wells penetrate the confining/injection zone. A total of 24 wells out of 45 are deep enough to penetrate the Confining Zone. However, only 12 of these wells extend deep enough to penetrate the top of the Injection Zone. Wells that do not penetrate the primary confining zone (Lower Cretaceous Sequence Boundary) do not provide potential avenues for fluid movement and need not be evaluated further.

A properly plugged well that penetrates the Injection Zones, will have at minimum, a plug set across the top of the Injection Zones. Plugging materials in artificial penetrations will be evaluated to determine if they are compatible with the CO_2 stream [40 CFR 146.84(d)].

7.1.3.1 Detailed Well Evaluation

Each artificial penetration located within the AoR was evaluated and this information is presented in **Appendix 10**. Only artificial penetrations that are projected to fall within the COI in any of the Injection Intervals, are evaluated against standards for non-endangerment. Out of the 45 wells in the AoR, only 12 wells extend deep enough to penetrate the Injection Zones. An additional pressure model evaluation is required for wells because of the following items:

1. there are no cement plugs placed in the borehole above the uppermost injection interval;
2. the wells penetrate the upperrmost injection interval (Lower Hosston) and are potentially in pressure communication with the injection well;
3. the annular space of the outermost casing string across the injection interval is potentially or known to not be cemented across the injection intervals; or
4. the outermost casing string across the injection intervals has not been perforated and squeeze-cemented, effectively sealing the annular space to potential vertical fluid movement.

Ten wells do not pass the initial screening protocol and require an additional pressure model evaluation. The wells are modeled by first comparing the predicted pressure increase from the dynamic simulation with the conservatively calculated allowable pressure buildup (static column pressure plus minimum gel strength) at each well, using well-specific information contained in the well detail construction tables. In cases where information was not available, conservative assumptions are made in the model calculations based on nearby drilling practices. The assumptions are summarized below:

a) For purposes of calculating gel strength, in cases where the open-hole borehole diameter across the injection interval sands is unknown, the surface casing outer diameter is used as the "equivalent" bit size. This is conservative since the actual bit diameter **must** be less than the inner diameter of the surface casing string. Additionally, in order to be conservative in the calculation, one inch is added to the bit diameter to account for borehole washout.

b) For purposes of calculating gel strength, in cases where uncemented protection casing extends across the injection intervals (i.e., top of cement is below the injection interval), the protection casing diameter across the injection interval is used as the "effective" hole radius. This is conservative since the actual borehole diameter minus the protection casing diameter is significantly less than the outer diameter of the protection casing string.

c) For purposes of calculating gel strength, a conservative gel strength of 20-lb/100 sq. ft. is used. This is conservative as studies indicate that with time, the gel strength of mud is very likely to be more than an order of magnitude higher (Pearce, 1989).

d) For purposes of calculating the static mud column pressure, in cases where the weight of the mud in contact with the injection intervals is not available, a conservative drilling mud weight of 9.3 lb/gal is used for all wells drilled prior to 1990 if the data is unknown. This is conservative since the available drilling information from area well logs indicates that the mud weight used to drill through the Cotton Valley Formation is have been demonstrated as greater than 9.3 lb/gal., and that even heavier muds were used.

e) In order to add a margin of safety in calculating the static column pressure, a fallback of 50 feet in the mud column height is assumed in the calculations. This is conservative, as state regulations require that <u>all</u> uncemented intervals in a well be filled with mud. Additionally, mud extending to surface is required to support the surface cement plug; otherwise, the plug would not set properly and would fall down the hole.

The calculations used in the modeling assessment are presented below.

A static fluid column exerts pressure. The pressures acting on the static fluid column (pressure due to injection plus original formation pressure) must be greater than the static fluid column pressure, before fluid movement will start. In this case, for upward fluid movement to begin, original formation pressure (P_f) plus the pressure due to injection (P_i) must be greater than the static fluid column pressure:

$$P_f + P_i > P_s$$

Where:

P_f = original formation pressure (psig)

P_i = formation pressure increase due to injection (psi)

P_s = static fluid column pressure (psig)

In other words, pressure increase due to injection must be greater than static fluid column pressure minus original formation pressure:

$$P_i > P_s - P_f$$

Static fluid column pressure is calculated using the equation:

$$P_s = 0.052 \times h \times M$$

Where:

P_s = pressure of static mud column (psi)

h = depth to the injection reservoir from the 50-foot fallback (feet)

M = fluid weight (lb/gal)

and 0.052 is the conversion factor so that P_s is in psi.

In an artificial penetration filled with a column of drilling mud, the gel strength of the mud must also be considered. In this case, for upward fluid movement to begin, original formation pressure (P_f) plus the pressure due to injection (P_i) must be greater than the static fluid column pressure plus the gel strength of the mud. This relationship is based on a simple balance of forces (Davis, 1986):

$$P_f + P_i > P_s + P_g$$

Where:

P_f = original formation pressure (psig)

P_i = formation pressure increase due to injection (psi)

P_s = static fluid column pressure (psig)

P_g = gel strength pressure (psi)

Therefore, pressure increase due to injection must be greater than static fluid column pressure minus original formation pressure:

$$P_i > P_s + P_g - P_f$$

For purposes of calculating the static mud column pressure, in cases where the weight of the mud in contact with the injection intervals is not available, a conservative drilling mud weight of 9.3 lb/gal is used for all wells. This is conservative since the available drilling information from area well logs indicate that the mud weight used to drill through the deepest formation (Cotton Valley) was always greater than 9.3 lb/gal, thus providing a margin of safety to these calculations.

The pressure due to gel strength (G) in an open borehole can be calculated from the following equation:

$$P_g = \frac{0.00333 \text{ x } G \text{ x } h}{d}$$

Where:

P_g = pressure due to gel strength (psi)

G = gel strength (lb/100 ft^2)

d = borehole diameter (inches)

Where 0.00333 is the conversion factor, such that P_g is in psi.

For a hypothetical open borehole, the added resistance due to gel strength for a mud with a very conservative ultimate gel strength of 20-lb/100 ft^2, in a 10-inch borehole, is approximately 6.7 psi for every 1,000 feet of depth.

For a cased hole, pressure due to gel strength (G) can be calculated from:

$$P_g = \frac{0.00333 \text{ x } G \text{ x } h}{d_b - d_c}$$

Where:

P_g = pressure due to gel strength (psi)

G = gel strength (lb/100 ft^2)

d_b = borehole diameter (inches)

d_c = outside casing diameter (inches)

For a hypothetical cased borehole, the added resistance due to gel strength for a mud with a very conservative ultimate gel strength of 20-lb/100 ft^2, in a 10-inch borehole with 7-inch casing is approximately 22.4 psi for every 1,000 feet of depth. However, in order to be conservative in the calculation, the effective annular diameter (d_b-d_c) between the borehole and the casing string is set to equal the outer diameter of the casing string only (*i.e.*, (d_b-d_c)$\simeq$ d_c). For the hypothetical case added resistance due to gel strength for a mud with a very conservative ultimate gel strength of 20 lb/100 ft^2, in a 10-inch borehole with 7-inch casing is conservatively calculated to be 9.5 psi for every 1,000 feet of depth.

As the above calculations show, gel strength provides a significant additional resistance to fluid movement due to injection. Additional conservatism is added to the present calculation by discounting borehole rugosity, which can increase the contribution in pressure from gel strength by a factor of 3 to 5 (Collins and Kortum, 1989) over that calculated for a "smooth" system. Using the above formulas for an open borehole and a cased borehole, the average measured gel strength from the Nora Schulze No. 2 well (267 lb/100 ft^2) (Pearce, 1989) and a factor of 3 contribution in gel strength due to borehole rugosity, the added resistance due to gel strength can reasonably be expected to be 266 psi per 1,000 feet of depth in an open borehole and 889 psi per 1,000 feet of depth in a cased well. To add a margin of safety in calculating the pressure due to gel, a fallback of 50 feet in the mud column is assumed.

The ten wells within the COI (delineated AoR) for each interval for the Lapis Project Blue site have been evaluated and the allowable pressure build for each well has been calculate. These are then compared to the pressure buildup at end of injection for each well to determine the safety factor as present in **Tables 34 and 35** below. All wells pass the secondary pressure evaluation.

Table 35: Pressure evaluation for wells within the AoR – Top of Lower Hosston Injection Zone

Artificial Penetration Number	Operator	Lease & Well Number	Calculated Strength due to Gel (psi)	Calculated Static Column (psi)	Allowable Pressure (psi)	Modeled Pressure* (psi)	Safety Margin (psi)
5	L.H. Wentz	S. Flournoy et al. No. 1	27	355	381	87	294
18	Schuler Drilling Company, Inc.	Brasher No. 1	30	386	416	60	356
23	O'Brien Operting Company Co.	J. Parnell et al. No. 1	48	263	311	75	236
24	Crude Oil LLC	J. Parnell No. 2	49	244	293	72	221
26	Kin-Ark Oil Company	Haney No. 1	48	491	540	69	471
28	Braddock Exploration, LTD.	McMahan No. 1	29	255	284	58	226
29	R.E. Williams	J. Parnell No. 1	30	346	376	75	301
30	T.L. James and Co - J.C. Wynne	Whatley No. 1	29	276	306	61	245
31	South Ranch Oil Company	I.G. Hammond et al. No. 1	48	180	229	73	156
52	Hurley Petroleum Corporation	Bush et al. No. 1	47	217	264	66	198

Table 36: Pressure evaluation for wells within the AoR – Top of Cotton Valley Injection Zone

Artificial Penetration Number	Operator	Lease & Well Number	Calculated Strength due to Gel (psi)	Calculated Static Column (psi)	Allowable Pressure (psi)	Modeled Pressure* (psi)	Safety Margin (psi)
5	L.H. Wentz	S. Flournoy et al. No. 1	31	414	445	230	215
18	Schuler Drilling Company, Inc.	Brasher No. 1	34	445	480	95	385
23	O'Brien Operting Company Co.	J. Parnell et al. No. 1	55	304	359	135	224
24	Crude Oil LLC	J. Parnell No. 2	56	282	338	125	213
26	Kin-Ark Oil Company	Haney No. 1	55	566	621	125	496
28	Braddock Exploration, LTD.	McMahan No. 1	34	306	340	130	210
29	R.E. Williams	J. Parnell No. 1	34	400	435	155	280
30	T.L. James and Co - J.C. Wynne	Whatley No. 1	34	326	360	135	225
31	South Ranch Oil Company	I.G. Hammond et al. No. 1	55	210	265	175	90
52	Hurley Petroleum Corporation	Bush et al. No. 1	56	260	316	110	206

7.1.3.2 Well Within the Plume

A total of five wells out of 45 are located within the operational and/or post-injection plume extent. Three of the wells (AP Nos. 1A, 1B, and 3) are not deep enough to penetrate the top of the LCSB Confining Zone. AP No. 7 penetrate just the top of the Confining Zone but does not extend deep enough to penetrate the Injection Zone.

The remaining AP No. 1 will be re-entered and recompleted as an In-zone monitoring well as part of the design provided in the "*E.1- Testing and Monitoring Plan*" submitted in Module D.

7.2 CORRECTIVE ACTION SCHEDULE

No improperly constructed or improperly plugged wells fail the conservative modeling screening evaluation. Therefore, a corrective action program is not warranted, as all the artificial penetrations are either properly constructed, plugged and abandoned (e.g., for CO_2 and brine vertical movement), or have sufficient resistant borehole material as to prevent the movement of brine into or between USDWs, or will be recompleted as part of the Testing and Monitoring Plan.

8.0 RE-EVALUATION SCHEDULE AND CRITERIA

8.1 AOR RE-EVALUATION CYCLE

Lapis Energy will reevaluate the previously described AoR at least once every 5-years during the injection and post-injection phases [40 CFR 146.84(e)]. Additionally, testing and monitoring of the site contains benchmarks/milestones that may trigger AoR reevaluations more often.

Testing and Monitoring data will be collected annually. Injection operations will be monitored at their set frequency. All data will be compiled and reviewed and then compared alongside the corresponding calculated output from the simulation model. The data will include (at a minimum):

1) Injection mass rates per day, volume rates, tubing head pressures and temperatures for the Injection Well.

2) Downhole pressures and temperatures daily for the Injection Well.

3) Where available, wireline logs of CO_2 injection rates per Injection Zone.

4) Pressure fall-off data, where available, for the Injection Well.

5) In zone and above zone pressure data from Monitoring wells.

The model will be updated with the actual daily historical CO_2 injection volumes for the Injection Well. The simulation model will be history matched to be representative of current conditions and then projected forward. Pressures will be monitored as presented in "*E.1 - Testing and Monitoring Plan*" submitted in **Module E** – Project Plan Submissions. Time-lapse pressure profiles will be compared between actual and predicted pressure profiles.

If a new AoR is delineated that will include additional Artificial Penetrations, these additional wells will be revaluated. These wells will be evaluated for status, construction and plugging details, location, and depth of penetration. It will be verified that each new well meets the standard to prevent the movement of CO_2 or other fluids out of the injection zone or endanger a lowermost USDW. If a well fails the evaluation criteria, the corrective action plan will be revised to include a deficient well.

8.2 TRIGGERS FOR AOR REEVALUATIONS PRIOR TO THE NEXT SCHEDULED REEVALUATION

Unscheduled AoR reevaluations may occur if unexpected changes are detected in the monitoring of the Project Blue site. Unexpected changes may be represented by fluctuations in pressure, temperature, water analysis, or major variations from modeled front behaviors. Examples that may trigger an earlier AoR reevaluation are as follows:

1. Increases in downhole pressures that exceed the model simulation and have an impact on the formation injectivity.

2. Increases in pressures in the above confining zone monitoring well which could indicate leakage above the formation.

3. A large decrease in expected formation pressures, which could indicate a leak.

4. An anomalous increase in CO_2 measured in the USDW in the El Dorado Chemical Company water supply wells, which cannot be explained.

5. Continuous monitoring systems determine that an injection operating parameter has been exceeded (such as total volume).

6. Additional site characterization information that will provide additional information.

7. Arrival times of Pressure/Plume fronts vary in the in-zone monitoring wells from modeled timeframes.

8. If at any time, the pressures in the monitoring wells exceed fracture gradient limits.

Details of events that may trigger a reevaluation based upon monitoring parameters are contained in the "*E.1 - Testing and Monitoring Plan*" submitted in **Module E –** Project Plan Submissions.

Lapis Energy will discuss any such events with the UIC Program Director to determine if an AoR reevaluation is required. If an unscheduled reevaluation is triggered, Lapis Energy will perform account for all information identified in the listing above.

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